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OIL REPLACEMENT ANALYSIS PHASE I

SELECTION OF TECHNOLOGIES

November 1984

This is an OTA Working Paper that has been neither reviewed nor approved by the Technology Assessment Board.

J 932-66

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OTA WORKING PAPER

This report is an OTA Working Paper, which was used in the preparation of OTA's final assessment report. OTA makes these working papers available for the use of readers desiring a more detailed or technical discussion of an issues than can normally be accomodated in our final report. An an OTA working paper, this report has not been reviewed or approved by the Technology Assessment Board. The findings and conclusions expressed in the report are those of the authors and do not necessarily reflect the views of OTA, the advisory panel, or the Technology Assessment Board.

Final Report

Oil Replacement Analysis Phase I—Selection of Technologies

Submitted to

Office of Technology Assessment
United States Congress
Washington, D.C.

April, 1983

Gibbs & Hill, Inc.

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I. EXECUTIVE SUMMARY

A. BACKGROUND

The Office of Technology Assessment (OTA) of the U.S. Congress has initiated a study to analyze various proactive and reactive options which can minimize the adverse impacts to the U.S. economy as a result of a 3 to 4 million barrels per day (MMbbl/d) cutoff in U.S. oil imports. As part of this project, Gibbs & Hill, Inc. (G&H) has undertaken a two phase study on rapid deployment of selected oil replacement technologies (ORT'S). The two phases of the G&H study are:

- Phase I - Selection of ORT's
- Phase II - Evaluation of selected ORT's.

The purpose of the G&H Phase I study is to screen the ORT's and identify those which can be rapidly deployed during the 1985-1990 timeframe on a cost-effective basis. The results of the G&H Phase I study described in this report are summarized below. G&H plans to evaluate the selected ORT's as part of its subsequent second phase efforts.

B. SUMMARY OF RESULTS

1. Prescreening of ORT's

An all-inclusive list of ORT's which are applicable in the four end-use consumption sectors (residential and commercial, industrial, electric utility, and transportation) is presented in Table III-1. Prescreening of these ORT's is performed to eliminate the technologies which:

a. are being evaluated by OTA under separate project efforts not involving G&H.

b. are not expected to be fully commercial by 1985 and/or they may require more than 5 years for implementation (from design to commercial operation).

c. are not expected to provide more than five percent of the potential short fall in imports.

After the prescreening analysis, the resulting list of ORT's is further narrowed down to fifteen candidate technologies which are listed in Table III-3.

2. Screening of Technologies

The fifteen candidate technologies are evaluated individually using a broad overview approach which is based on the following criteria:

a. Commercialization Status.

b. Oil replacement potential by 1990 in barrels of oil equivalent per day (boe/d).

c. Order of magnitude capital cost (1982 $/boe/d) and first year annual cost (1982 $/boe).

d. Major non-institutional constraints for deployment.

e. Major institutional and regulatory constraints for deployment.

The evaluation results described in Appendices A through O are summarized in Table IV-1. Based on the overview evaluations, a relative screening analysis is performed in Section IV by comparing candidate ORT's which can be deployed in each end-use consumption sector.

C. CONCLUSIONS

Based on prescreening and screening analyses, G&H has concluded that the following options are more cost-effective than others in minimizing the adverse impacts resulting from a 3-4 MMbbl/d short fall in U.S. oil imports.

a. Use of coal-water mixture (CWM) fuel in industrial and electric utility sectors.

b. Use of coal and wood in industrial facilities, and use of coal in utility applications.

c. Increased natural gas production, transportation and storage.

d. Accelerated deployment of enhanced oil recovery facilities.

e. Use of natural gas and liquefied petroleum gases (LPG) in vehicles.

f. Accelerated deployment of corn-to-ethanol production facilities.

D. RECOMMENDATIONS

Gibbs & Hill recommends that the above options be further evaluated during Phase II in accordance with the work plan discussed in Section V.

II. BACKGROUND

A. INTRODUCTION

The United States consumed an average of 16 million barrels of oil per day (MMbbl/d) in 1981, of which 6 MMbbl/d were imported from the Organization of Petroleum Exporting Countries (OPEC) and non-OPEC countries. Of the 3.3 MMbbl/d of OPEC imports in 1981, 1.8 MMbbl/d were from Persian Gulf countries.[1] The 1985 U.S. oil consumption is projected to be 16 MMbbl/d of which 4.8 to 5.6 MMbbl/d will be imported.[2, 3]

Given the current and projected dependancy on imported oil, a potential cutoff of 3 to 4 MMbbl/d in imports will have a significant adverse impact on the U.S. economy. To plan for such an emergency crisis, the Office of Technology Assessment (OTA) of the U.S. Congress has initiated a study to analyze various options which can be implemented prior to and during the oil cutoff.

One of the options being analyzed by OTA is the rapid deployment of selected oil replacement technologies during an oil cutoff. In support of its analysis, OTA authorized Gibbs & Hill, Inc. to undertake a two phased study:

1. Phase I - Selection of Oil Replacement Technologies

2. Phase II - Evaluation of Selected Oil Replacement Technologies.

The results of the G&H Phase I study (Selection of Oil Replacement Technologies) are presented in this report. Upon concurrence and approval of the study results, G&H will further evaluate the selected promising technologies (Phase II) so that constraints for their rapid deployment can be identified for inclusion into OTA's overall planning analysis related to emergency oil cutoff.

B. OBJECTIVES

The objectives of the G&H Phase I study are as follows:

1. Prepare an all-inclusive list of oil replacement technologies.

2. Prescreen technologies to identify an initial list of technologies which merit broad overview evaluation.

3. Screen technologies based on their broad overview evaluation so that promising technologies can be identified for Phase II analysis.

4. Prepare a work plan for Phase II analysis related to evaluation of selected oil replacement technologies.

C. SCOPE AND APPROACH

The scope of the G&H Phase I study includes a broad overview evaluation of energy supply technologies which can accomplish the following:

1. Fuel switching in the residential and commercial, industrial, electric utility and transportation sectors.

2. Increased use of domestic primary energy and renewable sources.

3. Accelerated production of synthetic fuels.

The study was performed by a team of technical specialists within G&H and its sister company, Dravo Engineers, Inc. (DEI). The specialists relied upon: their previous experience; in-house and published information sources; and responses received during telephone inquiries to industry associations, technology and equipment suppliers, and research institutions.

The results of the G&H study are presented in the following sections of this report:

1. In Section III, we present an all-inclusive list of oil replacement technologies. This initial list is then prescreened to eliminate those technologies which are not likely to be major candidates for rapid deployment during emergency oil cutoff and/or those technologies which are being studied by OTA under separate efforts not involving G&H.

2. In Section IV, we present a summary overview evaluation of selected technologies. These technologies are then screened to identify the most promising technologies which merit further evaluation as part of the detailed G&H Phase II efforts.

3. Section V presents the Phase II (Evaluation of Selected Technologies) work plan for G&H efforts.

4. Appendices (A through O) contain the results of overview evaluations performed by G&H specialists for individual oil replacement technologies.

D. REFERENCES

(1) DOE/EIA-0335(82/09), Monthly Energy Review, September 1982.

(2) OTA Staff Memo, T. Bull to N. Naismith and D. Strom, October 14, 1982.

(3) The Energy Daily, August 13, 1982 (Summary of Standard Oil of California Projections).

III. PRESCREENING OF TECHNOLOGIES

A. INTRODUCTION

The baseline scenario selected by OTA is a potential imported oil cutoff of 3 to 4 MMbbl/d beginning in 1985. The various oil replacement technologies which can be rapidly deployed within a five year period (1985-1990) under this scenario differ in several aspects, for example, technical characteristics, commercialization status (current and projected 1985), potential for oil replacement, economic considerations, and constraints for deployment. Given the diverse issues involved, a prescreening of technologies is necessary to eliminate technologies which are or will be only marginally feasible in 1985 for possible deployment during an oil cutoff. The results of our prescreening analysis are presented in this section.

B. INITIAL PRESCREENING LIST OF TECHNOLOGIES

The oil replacement technologies can be grouped in various alternative combinations. For example, technologies can be grouped based on primary energy source (e.g., coal, natural gas, secondary and tertiary oil from domestic wells, nuclear, etc.). Another possibility is to group technologies by end-use consumption sector and alternative energy supply options. Based on this latter approach, we have summarized in Table III-1, an initial all-inclusive list of oil replacement technologies.

TABLE III-1

INITIAL PRESCREENING LIST OF
OIL REPLACEMENT TECHNOLOGIES

End Use Consumption Sector	Energy Supply Option
1. Residential and Commercial	1. Natural Gas 2. Electricity 3. Wood 4. Solar (flat plate, photovoltaics-PV) 5. Coal 6. Wind 7. Conservation 8. Cogeneration
2. Industry (does not include any diesel and gasoline engines)	1. Natural Gas 2. Coal (direct-firing) 3. Coal Gasification, (on-site & off-site) 4. Coal Liquid Mixtures (coal-oil mixture-COM, coal-water mixture-CWM) 5. Wood 6. Solar (flat plate, PV) 7. Solid Waste 8. Geothermal 9. Biomass Gaseous Fuels (biogas, wood/plant gasification) 10. Wind 11. Cogeneration 12. Conservation
3. Electric Utility	1. Natural Gas (direct-firing & fuel cells) 2. Coal (direct-firing) 3. Coal Gasification, 4. Coal Mixtures (COM, CWM on-site & off-site) 5. Coal Liquids (coal-to--methanol, H-coal, SRC, synthoil, etc.) 6. Wood 7. Solid Waste 8. Solar 9. Wind 10. Geothermal

TABLE III-1 (Continued)

INITIAL PRESCREENING LIST OF
OIL REPLACEMENT TECHNOLOGIES

End Use Consumption Sector	Energy Supply Option
	11. Small Hydro
	12. Other-MHD, Fission, Ocean Thermal Energy Conversion (OTEC)
	13. Power Pooling
	14. Load Management
	15. Cogeneration
	16. Conservation
4. Transportation (includes stationary diesel and gasoline)	1. Natural Gas
	2. Electricity
	3. Biomas Liquid Fuels (ethanol, methanol)
	4. Biomass Gas (wood/plant gasification) and Coal Gas
	5. Coal Liquids (coal to methanol, MTG, H-coal, Fischer-Tropsch, EDS, etc.)
	6. Oil Shale, Tar Sands
	7. Conservation
5. All above	1. Enhanced Oil Recovery (EOR)

C. PRESCREENING OF TECHNOLOGIES

Various technologies listed in Table III-1 are eliminated from further evaluation for the following reasons.

1. Some technologies are being evaluated solely by OTA under separate efforts which do not involve G&H, these include:

   a. Conservation in all end-use sectors.

   b. Cogeneration in residential and commerical buildings, industrial, and electric utility sectors.

   c. Power pooling and load management in electric utilities.

   d. Biomass and coal-based gasification technologies for application in the transportation sector.

2. Some of the technologies are not expected to be fully commercial by 1985 and/or they require more than five years for implementation (from design to commercial operation). These technologies include electric utility sector options such as ocean thermal energy conversion (OTEC); nuclear fission, fusion and breeder reactors; and magnetohydro-dynamics (MHD).

3. Three technologies are not expected to provide significant (i.e. at least 5 percent of the short fall or 200,000 barrels of oil equivalent per day (boe/d)) oil replacement. These include the following:

   a. Use of wind energy for buildings, industry and electric utility sectors. Currently, wind energy for mechanical drive is being deployed at an annual incremental rate of 5 MW and increasing this rate to 1000 MW per annum by 1985 is not feasible. Similarly use of wind energy for electric power generation equivalent to 200,000 boe/d will entail installed wind-based capacity of 15,000 to 20,000 MWe because of low capacity utilization factors of 24 to 32 percent associated with wind-based electric power generating facilities.[1,2] A recent 126 MWe wind energy project planned for construction assumes a more optimistic capacity utilization of 37 percent[5], but when applied on a broad scale, assuming slightly lower values is considered prudent.

b. Use of geothermal energy for industrial and electric utility sectors. In the industrial sector, the oil replacement potential is severely limited because of the need for close proximity between the geothermal resource and industrial end-users. In the electric utility sector, current plans call for 3,000 MWe installed capacity by 1990. With maximum effort, the additional geothermal resource that can be located and exploited during the 1985-1990 period is an incremental 2500 MWe installed capacity.[3] This does not meet the 200,00 boe/d criteria.

c. Use of small hydro facilities for electric power generation. This technology is eliminated because its total oil replacement potential in the United States is estimated to be in the 80,000 to 140,000 bbl/d range.[4]

Based on the above rationale and analysis, the initial prescreening list of technologies is further narrowed down to 15 options which are listed in Table III-2. These alternatives are broadly screened and evaluated in Section IV.

TABLE III-2

LIST OF OIL REPLACEMENT TECHNOLOGIES
SELECTED FOR SCREENING EVALUATION

Alternate No.	Energy Supply/Technology-Description	Remarks/Examples
A.	Natural Gas in Buildings, Industries and Electric Utilities	Switch over from distillate/residual fuel oil to natural gas
B.	Electricity in Buildings	Use of heat pumps, resistance heaters and space heaters
C.	Coal and/or Wood in Buildings	-
D.	Coal, and Solid Wastes in Industries and Electric Utilities	Direct firing of coal
E.	Coal-Liquid Mixtures	Coal-oil, Coal-water mixtures
F.	Coal Gasification	low- and medium-Btu gasification
G.	Coal Liquefaction	-
H.	Oil Shale, Tar Sands	-
I.	Solar Energy	Use in buildings, industries and electric utilities
J.	Wood in Industries and Electric Utilities	Direct-firing both sectors; gasification in industries
K.	Biomass Liquid Fuels in Transportation	Use of ethanol from corn
L.	Natural Gas and LPG in Transportation	-
M.	Electricity in Transportation	-
N.	Enhanced Oil Recovery	-
O.	Increased Natural Gas Production Storage and Delivery	-

D. REFERENCES

(1) Scholl, M.M. and C.A. Zraket. "Solar Energy Systems & Resources," The MITRE Corporation, MTP-80W00001, 1980.

(2) Biro, G.G. "Analysis of Site Economics for Wind Energy Conversion Systems Selection," Presented by Gibbs & Hill at Fourth Miami International Conference on Alternative Energy Sources, Miami, December 1981.

(3) DiPippo, R. "Geothermal Energy as a Source of Electricity," DOE/RA/28320-1, January 1980.

(4) Feasibility Study for Small Scale Hydropower Additions Guide Manual, U.S. Army Corps of Engineer, July 1979.

(5) "126 Megawatts of Windmills,"The Energy Daily, December 10, 1982.

IV. SCREENING OF TECHNOLOGIES

A. INTRODUCTION

The fifteen oil replacement technologies selected for screening analysis are described and evaluated individually in Appendices A through O of this report. In this section we present the following:

- Summary evaluation of each technology
- Screening analysis
- List of technologies selected for Phase II analysis.

B. SUMMARY EVALUATION OF TECHNOLOGIES

The descriptions and overview evaluations of technologies are based upon our previous experience, in-house and published information sources, and responses received during telephone inquiries with industry associations, technology and equipment suppliers, and research institutions. For each technology, we have evaluated the following issues assuming that it is the only technology deployed during an emergency:

- Commercialization status
- Oil replacement potential in barrels of oil equivalent per day (boe/d)
- Order of magnitude capital cost (1982 $/boe/d) and annual cost (1982 $/boe)
- Major non-institutional constraints for technology deployment
- Major institutional and regulatory constraints for technology deployment.

Two potential non-institutional constraints, strategic materials and coal transportation are addressed at this point since they have broad applicability to oil replacement technologies.

1. Strategic Materials

With regard to the non-institutional constraint of strategic materials, the following general discussion is provided which forms the basis for assessing the potential constraint posed by either materials availability or cost.[1-4].

Strategic and critical materials are those that (a) would be needed to supply the military, industrial and essential civilian needs of the United States during a national emergency, and (b) are not found or produced in the United States in sufficient quantities to meet such needs.

Analysis of domestic production, consumption and imports of ores and metals reveals that U.S. industry is vulnerable to supply disruptions from foreign sources. During an oil supply disruption this supply of strategic materials may be sharply curtailed as a result of increased world demand, political upheavals and wars, escalating prices and/or arbitrary actions by suppliers. It is not in the scope of this study to predict which of these events may occur but rather to identify those oil replacement technologies whose implementation is most constrained by either unavailability or increased cost of strategic materials. Since every oil replacement technology relies on strategic materials to some degree for implementation, the relative importance of these materials among the technologies must be assessed.

Based on current U.S. production and consumption, strategic materials are columbium, manganese, tantalum, cobalt, aluminum, chromium, platinum group metals, tin, nickel, cadmium, zinc, tungsten and mercury. Strategic metals such as chromium, cobalt, tantalum and columbium are particularly critical since they do not occur in significant quantities in the American continents. Approximately 70 percent of the manganese as ore or ferromanganese comes from overseas and no substitute has been found for its use in the steel industry. Chromium availability is perhaps the most critical metal overall, for implementing oil replacement technologies because of its key alloy role in imparting corrosion resistance, hardenability and wear resistance. Other such as nickel are considered less critical because their import from Canada and other continental sources can be increased.

The technologies constrained the most will be those where the use of strategic materials is proportionally large with a resulting greater effect on the cost of implementing the replacement technology. Despite the importance of manganese in steelmaking, mild steel is not considered a critical material in comparing oil replacement technologies because of the small amount of this steel used in relation to the total U.S. production. The impact of increased steel prices due to decreased manganese availability will effect all oil replacement technologies. The grouping of technologies

by strategic material use, shown below, is based on the need for materials to provide high temperature strength, hardenability and resistance to corrosion, erosion and wear. Also considered is the ability of the technology to employ substitute, nonstrategic materials.

Relative Strategic Material Use:

- High - Coal gasification, coal liquefaction, tar sands, oil shale, enhanced oil recovery, increased natural gas supply.

- Medium - Direct combustion of coal, coal-liquid mixtures, wood gasification, biomass liquid fuels, electric vehicles (advanced), electricity in buildings (resistance heating), solar energy in utilities.

- Low - Natural gas in buildings, industry and utilities; coal and/or wood in buildings; solar energy in buildings and industry; wood combustion in utilities and industries; electric vehicles (conventional); electricity in buildings (heat pumps).

The above ranking of technologies with respect to strategic materials is based on the degree of use of typical components incorporating these materials:

- <u>High</u>

-- Coal gasification, coal liquefaction, tar sands, oil shale. These technologies have large use of materials and coatings containing high chromium, nickel and cobalt in components such as pumps, valves, vessel internals, cyclones and heat exchangers.

-- Enhanced oil recovery, increased natural gas supply. Drilling for gas and oil at greater depths results in more hostile environments. Sour gas and crude oil and well salt water environments require tubing, tools, valve and pump components, and oil/gas separation equipment made with alloys high in chromium, nickel and sometimes cobalt. The same is true for CO_2 gathering plants for CO_2 used in EOR.

- Medium

-- Direct combustion of coal, coal-liquid mixtures, wood gasification, biomass liquid fuels, and solar energy in utilities. These technologies require moderate use of stainless steel grades with chromium and nickel in heat exchangers, piping, vessel internals and coal handling. Wear resistant coatings are also required in coal mining and preparation.

-- Electric vehicles. Advanced battery systems have appreciable nickel content.

-- Electricity in buildings (resistance heating). Heating elements contain chromium, and may contain nickel.

- Low

-- These technologies have limited use of components containing strategic elements, and if they currently use components with strategic elements, substitution is readily available; such as copper alloys for stainless steel in moderate temperature applications.

The U.S. government stockpiles strategic materials for national defense and security purposes. An increasing number of companies are stockpiling nickel, cobalt, chromium, ferroalloys used in steelmaking, etc., in anticipation of supply shortages or steep increases in price. Besides stockpiling in a crisis situation, material substitutions and increased recycling as dictated by increased costs would be undertaken. It is assumed that strategic materials will be available after the oil disruption albeit at higher cost.

2. Coal Transportation

Since coal is the alternative fuel in many of the oil replacement technologies, an important area to address is the ability to transport the coal from the mine to the point of use. Rail and barge transportation of coal are assumed to provide the means of transportation. Any additional transportation capability via slurry pipelines, currently under consideration, has not been considered.

Based on a detailed evaluation of production forecasts for coal and other commodities competing for rail transportation, measures of railroad productivity, railroad critical component utilization, rail traffic density and railroad economic health, it has been concluded that the U.S. railroads and the critical railway supply industry will be able to handle an additional 11 quads per year (nearly 6 MMboe/d) of coal traffic in 1990.

A recent evaluation [10] concluded that there are no major constraints on the ability of the barge industry to handle projected increases in both domestic and export coal shipments.

Thus, it is concluded that the ability to transport the additional coal required in response to the oil disruption is not a constraint.

The overview evaluation results from Appendixes A through O are summarized in Table IV-1.

TABLE IV-1

SUMMARY OVERVIEW EVALUATION OF OIL REPLACEMENT TECHNOLOGIES

ALTERNATE	DESCRIPTION	COMMERCIALIZATION STATUS	1990 OIL REPLACEMENT POTENTIAL, boe/d	ORDER OF MAGNITUDE COSTS CAPITAL $/boe/d	ANNUAL $/boe	MAJOR NONINSTITUTIONAL CONSTRAINTS	MAJOR INSTITUTIONAL/ REGULATORY/ CONSTRAINTS
A	Natural gas in buildings, industries, and utilities	Commercial	Total: 0.44 MM (Buildings only)	16,000-25,000	64-69	. Requires 0.9 trillion cuft/yr of additional NG for buildings	None significant
B	Electricity in buildings	Commercial	Total: 0.60 MM (For Heat Pumps or Electric Heaters)	100,000-117,000 (Heat Pumps) 23,000 (Electric Heaters)	92-101 87	. Requires 147,000 MWe of capacity for either option (non-oil based)	None significant
C	Coal and/or wood in buildings	Commercial	Total: 0.44 MM	21,000 (coal or wood)	40 Coal 48 Wood	. Coal and wood distribution . Space limitations for fuel storage	. Air emissions . Ash disposal
D	Coal in utilities and industries	Commercial	0.46 MM utilities 0.24 MM industries 0.70 MM Total	25,000-46,000 (coal in utilities) 37,000-52,000 (coal in industries)	27-38 38-43	. Boiler derating . Space limitations for fuel handling and storage	. Environmental regulations
E	Coal - liquid mixtures	COM - Commercial CWM - pilot, CWM could become commercial by 1985	(MM) COM: 0.19 utilities 0.10 industries Total: 0.29 (COM) CWM : 0.46 utilities 0.24 industries Total: 0.70 (CWM)	23,200-28,900 (COM in utilities) 33,400-50,400 (COM in industries) 11,800-15,800 (CWM in utilities) 13,800-20,800 (CWM in industries)	34-38* 40-49* 25-28 26-30	. Boiler derating . Space limitations for onsite fuel preparation . Coal quality	. Environmental regulations

*Assume oil at $30/bbl. After oil disruption, 7-fold oil price increase would increase annual COM cost to approximately $80-90/boe for both sectors.

TABLE IV-1 (con't)

SUMMARY OVERVIEW EVALUATION OF OIL REPLACEMENT TECHNOLOGIES

ALTER-NATE	DESCRIPTION	COMMERCIALIZATION STATUS	1990 OIL REPLACEMENT POTENTIAL, boe/d	ORDER OF MAGNITUDE COSTS CAPITAL $/boe/d	ANNUAL $/boe	MAJOR NONINSTITUTIONAL CONSTRAINTS	MAJOR INSTITUTIONAL/ REGULATORY/ CONSTRAINTS
F	Coal gasification	Low to medium pressure units are commercial. High pressure units in demonstration state and could become commercial by 1985.	340,000 for industries	47,000-73,000 (Low Btu gas for industries)	43-58	. Lead time . Space limitations . Water availability . Boiler derating for low-Btu gas	. Environmental regulations
G	Coal liquefaction	Indirect liquefaction is commercial. Direct liquefaction is in pilot/demonstration state and may not become commercial during 1985-1990.	Not significant	45,000-75,000 (Indirect) 60,000 (Direct)	140-160** 80**	. Leadtime . Water availability	. Environmental regulations
H	Tar sands and oil shale	Commercial	Not significant	36,000-45,000 (Tar Sands) 35,000-55,000 (Oil Shale)	22-28** 50-60**	. Leadtime . Water availability . Lack of infrastructure near resource location	. Environmental regulations
I	Solar energy in buildings, industries, and utilities	Solar thermal commercial for buildings; photovoltaics for buildings in demonstration state; solar in industries and utilities in pilot scale could reach demonstration state for utilities during 1985-1990.	1985 installed solar for buildings capacity could be 15,000 boe/d. Capacity will probably not reach required 200,000 boe/d by 1990. Oil replacement of 75,000 boe/d is feasible by 1990.	335,000 (solar thermal for buildings) 900,000 (photovoltaics for buildings) 70,000-200,000 (solar thermal in industry) 70,000-100,000 (solar thermal in utilities)	80-200 500 80 37-55	. Manufacturing of collectors . Solar insolation	. None significant
J	Wood in utilities and industries	Commercial	Utilities-less than 40,000 Industry-340,000	21,000-31,000 (utility-combustion only) 38,000-50,000 (industry-gasification) 32,000-38,000 (industry-combustion only)	22-28 36-43 31-34	. Proximity of resource to end users . Land at end user	. Environmental

**Based on oil at $30/bbl.

TABLE IV-1 (con't)

SUMMARY OVERVIEW EVALUATION OF OIL REPLACEMENT TECHNOLOGIES

ALTERNATE	DESCRIPTION	COMMERCIALIZATION STATUS	1990 OIL REPLACEMENT POTENTIAL, boe/d	ORDER OF MAGNITUDE COSTS CAPITAL $/boe/d	ANNUAL $/boe	MAJOR NONINSTITUTIONAL CONSTRAINTS	MAJOR INSTITUTIONAL/ REGULATORY/ CONSTRAINTS
K	Biomass liquid fuels in transportation	Commercial (corn to ethanol is the principal technology)	Current production capacity of 7,000 boe/d, could probably not be increased to 200,000 boe/d required by 1990.	20,000-35,000	220 (unsubsidized) 150 (with subsidies)	. Requires 20 million acres of new cropland . Requires increased fertilizer production . Requires coal transport to corn belt.	. Environmental regulations
L	Natural gas/LPG in transportation	Commercial	CNG: 1,600-2,400 (current) 375,000 (incremental) LPG: 70,000 (current) 35,000 (incremental)	33,000-51,000 (CNG in fleet vehicles) 21,000-52,000 (LPG in private vehicles)	81-91 72-94	. Requires 1 trillion cu ft/yr additional NG . Public concerns about car safety	. Conflicts with car warranties . Tunnel and bridge prohibitions
M	Electric vehicles	Commercial	39,500	144,000-205,000	226-278	. Limited car performance	. Auto safety requirements
N	Enhanced oil recovery	Commercial	400,000 (current) 0.5-0.6 MM (1985 projection) 1.0 MM (additional by 1990)	4,000-20,000 (Steam Flooding) 20,000-41,000 (CO_2 Flooding)	27-35 26-62	. Increased CO_2 production . May require coal for fuel injection . Leadtime . Location of refineries vs. resource production . Water availability	. Environmental regulations air pollution, water quality
O	Increased natural gas supply	Commercial	2 MM	60,000-120,000	55	. Storage location . Land availability	. Regulations on prices and construction of network

Notes

See Appendices A through O for details. 1990 oil replacement potential is an estimated target on a national basis which could be achieved by rapid deployment: All costs are in 1982 $. Annual costs are first-year costs based on 20 percent per year charge on capital and O&M and fuel expenses.

C. SCREENING ANALYSIS

Based on the results shown in Table IV-1, we present below a relative screening analysis of the technology options for each end-use consumption sector. The purpose is to narrow down the options and identify those technologies which merit further detailed analysis as part of the G&H Phase II efforts.

1. Residential and Commercial Buildings Sector

During an imported oil cutoff, distillate oil or kerosene used in this sector can be replaced by natural gas, electricity, coal, wood, or solar thermal systems. Each of these options has inherent constraints (see alternates A,B,C and I of Table IV-1).

It is likely that coal and wood use in buildings will be accelerated because of economic incentives, and, hence these options do not require further evaluation as part of OTA's current planning analysis. Use of electricity in buildings could be constrained by the availability of non-oil based electric energy by 1990. OTA is evaluating this issue separately and this is excluded from G&H's Phase II scope.

On a national basis, use of solar thermal systems for buildings is not cost effective. However, in certain regions with high solar insolation this option would be attractive. The oil replacement in these regions, which is identified in Appendix I, is estimated to be 75,000 - 100,000 boe/d.

Use of natural gas in buildings is constrained by supply of natural gas rather than by end-use conversion constraints. As part of Phase II efforts, G&H plans to further evaluate increased natural gas production, storage and delivery (see Alternate O in Table IV-1).

2. Electric Utility Sector

Coal reconversion of electric utility boilers via direct firing of pulverized coal is a proven technology which is already being deployed in the country. Of the two coal-liquid mixtures options (see Alternate E in Table IV-1), coal-water mixture (CWM) is more cost-effective than coal-oil mixture (COM) for use in the electric utility sector. Consequently, CWM technology, which is an emerging option, is selected for further evaluation as part of G&H Phase II efforts.

3. Industrial Sector

CWM could be a more viable option than COM for industrial boilers (see Alternate E in Table IV-1) and is selected for Phase II evaluation. Direct coal- and wood-firing are more cost effective than coal-derived and wood-derived low Btu gas (see Alternates D and F in Table IV-1). However, U.S. production capacity for solid fuel-fired boilers could be a constraint in an oil cut-off. Consequently, both direct- and gasified-firing of coal and wood are selected for further evaluation in Phase II.

4. Transportation Sector

Electric vehicles (see Alternate M in Table IV-1) are not expected to play a major role in the 1985-1990 period. Natural gas and Liquefied Petroleum Gases (LPG) can be used to power vehicles (see Alternate L). However, this option is constrained by availability of natural gas and LPG derived from natural gas. As part of Phase II efforts, G&H plans to verify whether manufacturing constraints are critical for deployment of natural gas and LPG driven vehicle technology. Ethanol production from corn is a commercially proven technology and G&H plans to identify technical and manufacturing constraints, if any, in accelerating the installation of ethanol production facilities.

5. Primary Energy Sources

Coal liquefaction, oil shale, and tar sands facilities (Alternates G and H in Table IV-1) are not expected to offer any significant oil replacement potential during the 1985-1990 time frame. Enhanced oil recovery (Alternate N) and increased natural gas production (Alternate O) could be viable and will be further studied as part of G&H Phase II efforts.

D. SUMMARY LIST OF TECHNOLOGIES SELECTED FOR PHASE II ANALYSIS

Based on the relative screening analysis mentioned earlier, the following technologies and issues will be further studied as part of the G&H Phase II efforts:

1. Technologies

a. Coal water mixture in industrial and utility applications.

b. Direct-firing of coal utility applications, and use of coal and wood in industrial applications.

c. Increased natural gas production, transportation, and storage.

d. Accelerated deployment of enhanced oil recovery technology.

2. Issues

a. Manufacturing constraints for accelerated use of natural gas and LPG driven vehicles.

b. Constraints for accelerated deployment of corn-to-ethanol production facilities.

The G&H Phase II work plan is presented in Section V.

E. References

(1) Gray, A.G. "Substitution/Conservation Technology For Critical Material," Metal Progress, December 1981.

(2) Hurlich, A. "Strategic Materials - Technological Trends," Mechanical Engineering, July 1982.

(3) Gray, A.G. "Materials Substitution: Challenge of the 80's," Metal Progress, February 1980.

(4) "Realities of Energy Materials," Metal Progress, February 1981.

(5) "Materials and Components," U.S. DOE, Numbers 21 (4/1/79), 26 (2/1/82), 28 (6/1/82), 31 (4/1/81), 39 (8/1/82) and 42 2/1/83).

(6) Irving, R.R., "Materials Comes First in Sour Gas Drilling," Iron Age, November 12, 1980.

(7) "Nickel Alloy in Oil Country Tabular Goods and Other Petroleum Equipment," Huntington Alloys Brochure, December 1982.

(8) Metals Handbook, American Society For Metals, Ninth Edition, Volumes 1 and 4, 1979 and 1981.

(9) Dellacanonica, O.G. "Coal Transportation by Rail in the United States, Will the Nations Railroads Successfully Cope with the Projected Demands?," Gibbs & Hill, October 5, 1981.

(10) "Moving U.S. Coal to Export Markets. An Assessment of the Transportation System's Capability to Handle Future Coal Traffic," Army Corps of Engineers, et. al, Draft, June 10, 1980.

V. PHASE II WORK PLAN

The energy supply technologies selected in Phase I as most promising for oil replacement will be examined in greater detail in Phase II. The objective of Phase II is to verify and refine, where necessary, the oil replacement potentials identified in Phase I by providing regional deployment rate curves as constrained by lead times, equipment and manpower availability, and environmental regulations. The tasks to be performed for each oil replacement technology are summarized below.

A. COAL-WATER MIXTURES (CWM)

1. Identify geographic region for deployment.

2. Estimate the number of boiler plants for the utility and industrial sectors in each region.

3. Establish average preparation and boiler plant sizes for both on-site and off-site CWM preparation in each sector.

4. Size critical components requiring long lead times, in both CWM preparation plants and boiler modifications.

5. Provide a schedule for rapid deployment of CWM technology (on-site and off-site preparation plants) with estimates of each critical path segment.

6. Compare peak yearly requirement of critical components to historic U.S. production capacity. Peak yearly requirement will be based on starting all projects of the same time, ie., overnight start after the oil cutoff. If equipment availability does not satisfy the accelerated demand under overnight start, the start of projects would then be staggered to verify if equipment availability constraints could be overcome.

7. Determine if bottlenecks created by skilled manpower shortages occur as a result of overnight start of all projects. If yes, the start of projects would then be staggered.

8. Determine the deployment rate of CWM fuel substitution for each region.

9. Review the $/boe costs from Phase I to determine if any major refinements are required as a result of the Phase II analysis.

10. Identify any technological and environmental "unknowns" that might restrict deployment of CWM fuels. Identify programs to be undertaken to address these "unknowns".

B. WOOD AND COAL COMBUSTION IN INDUSTRY

1. Identify geographic regions attractive for switching to wood and coal fuels (direct-firing or as low-Btu gas).

2. Estimate the number of boiler plants in the industrial sector to be repowered by wood and coal in each region.

3. Establish an average plant size for each fuel.

4. Size critical components requiring long lead times for each fuel.

5. Provide a schedule for rapid deployment of each fuel technology with estimates of each critical path segment.

6. Compare peak yearly requirement of critical components to historic U.S. production capacity. Determine this for overnight start and, if sufficient deployment cannot be accomplished, utilize staggered start of projects.

7. Determine if bottlenecks created by skilled manpower shortages occur as a result of overnight start of all projects. If yes, the start of projects would then be staggered.

8. Determine the deployment rate of each fuel technology for each geographic region.

9. Review the $/boe costs from Phase I to determine if any major refinements are required as a result of the Phase II analysis.

10. Identify any technological and environmental "unknowns" that might restrict switching to wood and coal fuels. Identify programs to be undertaken to address these "unknowns."

C. ENHANCED OIL RECOVERY

1. Identify geographic regions for deployment.

2. Estimate the number of steam and CO_2 injection projects in each region.

3. Establish the average steam and CO_2 injection project size.

4. Size critical components requiring long lead times for both type of projects.

5. Provide a schedule for rapid deployment of a steam and a CO_2 injection project.

6. Compare peak yearly requirement of critical components (e.g. drilling rigs) to availibility and to historic U.S. production capacity. Determine these areas for overnight start and, if sufficient deployment cannot be accomplished, utilize staggered start of projects.

7. Determine if bottlenecks created by skilled manpower shortages occur as a result of overnight start of all projects. If yes, the start of projects would then be staggered.

8. Determine the deployment rate of each type of project for each region.

9. Review the $/boe costs from Phase I to determine if any major refinements are required as a result of the Phase II analysis.

10. Identify any technological and environmental "unknowns" that might restrict EOR projects including transportation of oil to refineries that can process the recovered oil. Identify programs to be undertaken to address these "unknowns."

D. NATURAL GAS PRODUCTION, TRANSPORTATION AND STORAGE

1. Identify, regionally, the areas of natural gas production (unconventional), transportation routes to end-user regions and storage areas.

2. Estimate the number of drilling sites, additional pipelines and storage caverns.

3. Describe critical components related to natural gas production (unconventional), transportation and storage.

4. Provide a schedule for rapid deployment of natural gas production, transporation and storage.

5. Compare peak yearly requirement of critical components to availability (such as drilling rigs) and to historic U.S. production capacity. Determine these areas for overnight start and, if sufficient deployment cannot be accomplished, utilize staggered start of projects.

6. Determine if bottlenecks created by skilled manpower shortages occur as a result of overnight start of all projects. If yes, the start of projects would then be staggered.

7. Determine the deployment rate for additional natural gas production, transporation and storage.

8. Review the $/boe costs from Phase I to determine if any major refinements are required as a result of the Phase II analysis.

9. Identify any technological and environmental "unknowns" that might restrict deployment of additional natural gas production, transportation and storage. Identify programs to be undertaken to address these "unknowns."

E. CNG/LPG POWERED VEHICLES

1. Determine critical components required for converting vehicles to CNG/LPG powering.

2. Compare peak yearly requirement of critical components to historic U.S. production capacity.

3. Determine the deployment rate for CNG/LPG powered vehicles.

F. ETHANOL FROM CORN

1. Provide a schedule for rapid deployment of ethanol plants, including both the field erected type and prefabricated ones.

2. Identify critical components for both type plants.

3. Compare peak yearly requirement of critical components to historic U.S. production capacity.

4. Determine deployment rate of ethanol plants.

A. NATURAL GAS IN BUILDINGS, INDUSTRIES AND UTILITIES

CONTENTS

1. Introduction

2. Commercialization Assessment

3. Oil Replacement Potential

4. Cost

5. Non-institutional Constraints

6. Institutional Constraints

7. References

LIST OF EXHIBITS

A-1 Capital Cost for Converting Buildings to NG Firing

A-2 Assessment of Manufacturing Capacity Required for NG Conversion

1. Introduction

The use of natural gas (NG) as a substitute for residual and distillate oil in residential and commercial buildings, industries and electric utilities is a proven commercial technology which has been successfully used for many years. Of the three end-use sectors, conversion of buildings during an imported oil cut-off is of primary concern and is discussed in this Appendix.

The substitution of NG for fuel oil in residential and commercial boilers involves only the removal of the oil burner and the substitution and adjusting of the gas burner. The remainder of the boiler, distribution piping, radiators, convectors, etc., remain unchanged. In about 20 percent of the cases (both residential and commercial) it may be necessary to replace the entire boiler because of the poor physical condition of the existing unit[1, 10, 11, 12].

The domestic hot water is either heated within the steam boiler, in which case its conversion to gas is considered with that of the comfort heating or, if separate, is generally already heated by NG or electricity. Since a negligible number of oil-fired hot water heaters are used solely for hot water, any conversion of fuel oil usage to NG in these heaters is negligible and will not be discussed further[2].

2. Commercialization Assessment

The technology for the change from oil to gas (or vice versa) has been in successful operation for many years. The equipment and installation have been guaranteed and the safety record of this modification has been exceptional. No strategic material is involved in this change and, thus, no bottlenecks would result.

3. Oil Replacement Potential

The projected fuel requirement for heat and domestic hot water in 1985 is estimated at: [3]

Distillate oil	773,000 bbl/day
Liquefied Petroleum Gases (LPG)	295,000
Kerosene	107,000
	1,175,000 bbl/day

In the U.S., 68.5 percent of the single-family and mobile homes have natural gas available and 87 percent of these

homes use natural gas as the main source of heating.[9] Natural gas appears to be the preferred fuel when available.

LPG is derived from crude oil and natural gas processing plants. Use of LPG for heating is primarily in rural areas (about 86 percent of the total)[9] and the conversion of LPG-fired units to NG will not be cost effective. It is assumed that these units could be replaced by wood- or coal-fired units and the additional LPG from increased natural gas production (see Appendix O) will satisfy the LPG requirement for units not converted to coal or wood.

In 1980, of the 13.4 million households which used fuel oil or kerosene as the main heating fuel, 8.6 million households (or 64 percent) were in urban areas with, the balance being in rural areas [9]. It is feasible and cost effective to install the required network of small distribution pipes to individual households only in areas of dense population. (Distribution is addressed in Appendix O.) Thus, it is assumed that about 50 percent of the households could be converted to NG during an imported oil cutoff.

In urban areas in the U.S. nearly 90 percent of the single-family and mobile homes that have natural gas available, use natural gas [9]. Thus, whether the neighborhood distribution lines are new (see Appendix O) or existing, it can be assumed that they are of sufficient size to service any additional household capacity requirements.

It is estimated that the 13.4 million households which use fuel oil or kerosene comprise about 9.5 million units as follows[9]:

Single family units	: 7.9 million (MM)
Attached single family units	: 0.7 MM
Buildings with 2 to 4 families	: 0.5 MM (*)
Buildings with 5 or more families	: 0.4 MM (**)
Total	: 9.5 Million

Added to this number are the commercial conversions. Thus to achieve 50 percent conversion of oil and kerosene fired units to NG will entail about 5 million conversions. Such a market penetration by NG will replace 440,000 (=0.50 x 880,000) boe/d of distillate oil and kerosene.

4. Costs

Since the conversion to NG is anticipated to take place after the possible short-fall occurs, there is a strong incentive for residences and commercial establishments to bear the costs of conversion. The cost of additional NG is estimated to be $55/boe (see Appendix O).

The cost of converting residential and commercial boilers and hot air furnaces from fuel oil to NG is estimated at $7.2 to $11.1 billion or 16,000 to 25,000 $/boe/d. (See Exhibit A-1.) At a 20 percent fixed charge rate this is equivalent to a fixed charge of 9 to 14 $/boe and an annual cost of conversions to NG at 64 to 69 $/boe.

5. Non-institutional Constraints

No highly skilled labor is required for residential/commercial conversions.[6,10,11] Licensed plumbers do not perform the actual conversions. Rather, it is performed in most cases by trained service men working under the license of one man. This is true whether the utility is performing the work or the work is left to the plumbing trade. This situation is common practice. A shortage of semi-skilled labor can be corrected in a reasonably short time by establishing training through public utilities as well as other training facilities. Consolidated Edison estimates that the training period would amount to about one month for people who have experience with pipe fitting procedures[6]. This does not represent a constraint.

Sufficient facilities for manufacturing of burners and valves exist to keep up with the rate of installation. Assuming plants which manufacture these parts also manufacture other similar items, and if necessary, go to multiple shifts, supply of burners and valves would not constitute a critical time element in this conversion. (See Exhibit A-2.)

Transportation of these small items constitutes no problem to this conversion nor does space limitation affect the choice.

This is not a capital intensive modification. The basic machinery for manufacturing the burners and valves is already available.

6. Institutional and Regulatory Constraints

Ordinarily, in most locations, a licensed plumber must be in charge of the conversion installation. However, as with Brooklyn Union Gas Company, there is one licensed plumber and

many qualified individuals that work under him, who perform the conversions. This approach has not compromised the safety of these installations. Furthermore, in a crisis situation, limited licenses may be issued to skilled people who have received enough specialized training, to be capable of performing the conversion from fuel oil to a safely operating gas burner[6].

EXHIBIT A-1

CAPITAL COST FOR CONVERTING BUILDINGS TO NG FIRING

The average cost for a residential conversion that does not entail replacing the boiler is about $600 to $800 [10,11]; for commercial conversions the cost is $1,500 to $3,000. To run a piping connection from the building to the street distribution line for residential and commercial units costs about $500 to $700.

The average cost when the residential boiler or hot air furnace must be replaced is about $2,000 to $2,500[1, 10, 11] for a 80 to 100 MBtu/hr unit. Based on the wide size range of commercial units, costs range from $5,000 to $15,000.

Of the 5 million conversions, assume 80 percent entail use of existing boilers or furnaces and 20 percent require new boilers or furnaces[6]. The capital cost of these conversions is as follows:

$0.80 \times 4.5 \times 10^6 \times \$(1100 - 1500)$ =	$4.0 - 5.4 billion
$0.80 \times 0.5 \times 10^6 \times \$(1500 - 3000)$ =	$0.6 - 1.2 billion
$0.20 \times 4.5 \times 10^6 \times \$(2500 - 3200)$ =	$2.3 - 2.9 billion
$0.20 \times 0.5 \times 10^6 \times \$(5,500-15,700)$ =	$0.5 - 1.6 billion
Total Capital Cost =	$7.2 - 11.1 billion
Oil replaced =	440,000 boe/d
Capital Cost, $/boe/d =	16,000 - 25,000

EXHIBIT A-2

ASSESSMENT OF MANUFACTURING CAPACITY REQUIRED FOR NG CONVERSIONS

In 1980, 1.2×10^6 households converted from fuel oil or kerosene[4]. Assuming that 2/3 of these conversions were to NG, there were 800,000 conversions from fuel oil to NG in 1980.

Both Brooklyn Union Gas and Consolidated Edison have indicated a disappointing amount of conversion with a large inventory of burners and valves[1][6]. Assume that the burner and parts manufacturing facilities operated at 70 percent of capacity and 75 percent of the parts which were manufactured in 1980 were actually installed in residential boilers. Thus, it is estimated that 1.5×10^6 burners and valves ($= 0.8 \times 10^6 / 0.70 \times 0.75$) could have been manufactured in 1980.

Based on this estimated manufacturing capacity, the required 5 million conversions during the oil cutoff could be accomplished in 3.5 yeras and manufacturing capacity will not be a constraint.

In 1980, 293,000 boilers of residential capacity were shipped by manufacturers[8]. Assuming the manufacturers were operating at 70 percent of capacity, the required 1 million replacement boilers can be manufactured in about 2.5 years. Thus the manufacturing of replacement boilers is not expected to be a constraint.

While no data is available for commercial boiler manufacturing, an analysis of facilities, usages and requirements should yield a very similar time frame.

7. References

(1) Steve Renna (Brooklyn Union Gas Co.) personal communication (20 October 1982).

(2) "Residential Energy Conservation Survey: Housing Characteristics, 1980," DOE/EIA-0134 of June 1982, Table 20, pg. 92.

(3) Memo from Tom Bull to N. Naismith and D. Strom. "Rationale for Deemphasizing Certain Types of Petroleum Uses as Candidates for Replacement During an Oil Short-Fall," October 14, 1982, Table 2.

(4) Residential Energy Conservation Survey; OP. Cit. Table 17, pg. 81.

(5) Ibid, Table 19, pg. 87.

(6) Martin Gitten (Consolidated Edison) personal communication (20 October 1982).

(7) Draft - Scope of Work OTA US 82-8, "Oil Replacement Analysis," pg. 4.

(8) "Gas Facts, 1980," AGA., pg. 133, Table 108.

(9) Residual Energy Conservation Survey; Op. Cit, Table 19, pg. 87 Table 27, pg. 124 and pg. 7.

(10) Charles Setian (Bay State Gas Co., Boston) personal communication (March 2, 1983).

(11) Dan Lauria and Paul Ridgeway (Connecticut Natural Gas Corp., Hartford) personal communication (March 2 and 7, 1983).

(12) Rich Itelog and Alan Caron (American Gas Association) personnel communication (March 2, 1983).

B. ELECTRICITY IN BUILDINGS

PART 1: HEAT PUMPS

CONTENTS

1. Introduction

2. Commercialization Assessment

3. Oil Replacement Potential

4. Costs

5. Non-institutional Constraints

6. Institutional Constraints

7. References

LIST OF EXHIBITS

B-1-1 Electric Generating Capacity Required to Replace 0.88 Million Bbl/day

B-1-2 Estimated Capital Cost for Conversion to Heat Pumps

B-1-3 Time Required for Manufacturing of Heat Pumps

1. Introduction

The substitution of electric power employing heat pumps(*) for residential and commercial installations in place of fuel oil heating, involves the use of central heat pumps for forced warm air furnaces and unitary heat pumps for hydronic and steam heated applications. In the former case, the existing ductwork and fan are retained and used. In the latter case the steam and hot water heating systems are not used. The heat pumps considered for this study are "heating only" air-to-air heat pumps in order to achieve greater efficiency at low temperatures. Domestic hot water systems which are oil fired would be replaced by electric hot water heaters.

2. Commercialization Assessment

Two types of air-to-air heat pumps are considered as being appropriate.

a. For those installations which use oil to fire a forced warm air furnace, a central heat pump may be added to the existing system. There are 4.8×10^6 households which fall into this category.[1] It is assumed that these households occupy mainly single family units and 4.8 million central heat pumps will be required.

b. For the hydronic or steam distribution systems which use fuel oil, unitary heat pumps (individual units for designated areas or rooms) could replace the entire previously used heating system. There are 8.6×10^6 households which fall into this category.[1] It is assumed that these households occupy approximately 5 million buildings.

Water to air heat pumps are not considered because sufficient sources of water are already becoming scarce [2] and an immense increase such as this would require, could not be accommodated.

The technology for these two types of installations has been in successful operation for many years. The equipment is guaranteed and the installation is subject to code and specification requirements.[3]

These conversions can be accomplished within the five year time frame of this study, and, may be very appropriate for

*Implicit in this substitution is the understanding that fuel oil will not be used in generating the electric power.

outlying non-urban areas, where alternate distribution of NG would be costly and time-consuming. (See Exhibit B-1-3.)

The conversion from oil heating to electric heat pumps cannot be applied until the bulk of the fuel oil burning electric power capacity has been converted to other fuels.

3. Oil Replacement Assessment

The oil replacement assessment is the anticipated non-residual oil usage for heat and domestic hot water, minus the LPG usage for this market. This is as follows:

$1.175 \times 10^6 - 0.295 \times 10^6 = 0.88 \times 10^6$ bbl/day. [4]

As opposed to natural gas, which permits conversions only in households with potential for gas distribution line hook-up, conversions to electric heat (heat pumps or resistance) are not limited to urban areas. Thus, all the fuel oil/kerosene used could potentially be replaced by electricity.

The amount of electric power consumed for heating would be reduced to about 66 percent of that for electric resistance heating if conventional heat pumps were installed.[5] However, for a heat pump designed for heating only and operating efficiently down to 20 F; the reduction would amount to about 50 percent.

Since at extreme winter conditions, the heat pump efficiency would be reduced to the point where resistance heating would have to carry the entire load, the additional electric generating capacity would have to be 147,000 MW. (See Exhibit B-1-1.)

4. Costs

The average price for residential/commercial electric power is about 6.9¢/kW-hr.[6] This equates to a fuel charge as follows:

$$\frac{(\$0.069/\text{kW-hr})(5.5 \times 10^6 \text{ Btu/bbl oil})}{3413 \text{ Btu/kW-hr}} = \$111/\text{boe},$$

taking into account the average inefficiency of fuel oil combustion yields (\$111)(0.67) = \$74/boe.

Accounting for the average coefficient of performance (COP) at which these heat pumps will perform, the comparable cost corresponding to fuel oil price is:

(\$74/boe) (0.50)[5] = \$37/boe.

This "average" COP includes those times when the outside air temperature is below 20 F and electric resistance heating is used.

The cost of installation of heat pumps and domestic hot water heaters in place of oil heaters is \$88 to \$103 x $\$10^9$ (see Exhibit B-1-2) or \$100,000 to 117,000 dollars per barrel per day. At a fixed charge rate of 20 percent the fixed charge is 55 to 64 \$/boe bringing the total cost of heat pump conversions to 92 to 101 \$/boe.

5. Non-institutional Constraints

The labor force of skilled workers to install heat pumps on this scale does not exist at the present time. A training period of about six months would be required to train an electrician with a license limited to these activities only, and a similar period for the other trades. This does not represent a constraint. The manufacture of heat pumps and water heaters would be a constraint on this option at the beginning of the five year interval but would quickly catch up to the availability of skilled workers. The basic constraint is the availability of non-oil based electric power.

Installation of heat pumps is a capital and labor intensive modification. However, in a crisis, it constitutes one of the important prospects which must be considered, if only for a part of the solution.

6. Institutional and Regulatory Constraints

The manufacture and installation of the electric components are regulated by codes and standards; these will have to be complied with.[3] However, where a licensed electrician may have been required in the past, a limited license may be sufficient in the event of a crisis.

EXHIBIT B-1-1

ELECTRIC GENERATING CAPACITY REQUIRED TO REPLACE 0.88×10^6 BBL/DAY

In extreme winter conditions, the heat pump does not operate and the heating is performed by electric resistance heating components, which are part of the heat pump assembly. The electric generating capacity required to permit switching of all residential/commercial, non-residual oil use to heat pumps is the total power required for electric resistance heating. Assuming on the coldest winter day 50 percent of the units are operating at once, the average household total heating unit(s) capacity is 60,000 Btu/hr and electric conversion efficiency is 1.0, the total power required as:

$(0.5)\ (13.4 \times 10^6)(60{,}000\ \text{Btu/hr})/(1.0)\ (3413\ \text{Btu/kW-hr})\ (1000\ \text{kW/MW}) = 118{,}000\ \text{MW}.$

With an additional 15 percent power for commercial facilities and 10 percent for hot water heaters the total power required is 147,000 MW. This does not include any additional power required as a result of capacity factor considerations.

Planned Electric Power Resources in U.S. and Canada are as follows:[18]

Winter of 1982/1983	664,000 MW
Winter of 1989/1990	821,000 MW

We will subtract the WSCC region capacity due to a lack of transmission capability from this western-most region. Other lesser bottlenecks are already being corrected and by 1990 the tie-ins should be completed. Since these are either in construction or in planning, their costs will not be included in this study. For conservatism the Canadian capacity is subtracted as well. Since a small percentage of homes in the WSCC region are heated with oil, the 392,000 MW replacement power estimate need not be reduced.

	MW		
	NERC (US Only)	WSCC	NERC Less WSCC
Winter of 1982/1983	596,000	104,000	492,000
Winter of 1989/1990	726,000	132,000	594,000
Capacity added	130,000	28,000	102,000
Projected Peak Load (Winter 1989/90)			409,000
Projected Reserve (Winter 1989/90)			185,000

Using a reserve margin of 20 percent brings the power available to approximately 100,000 MW [= (594,000 MW) - [409,000 MW + (0.2) (409,000 MW)]. Since 30,000 MW of the 130,000 MW projected new capacity is not yet under construction [11], the available power could be further reduced. Thus, at best, it appears that only two-thirds (=100,000 MW/147,000 MW) of the 880,000 bbl/day of oil could be displaced by electric heat pumps. However, to verify this oil replacement by electric generating capacity will require a much more detailed analysis. Such an analysis is being conducted separately by OTA.

EXHIBIT B-1-2

ESTIMATED CAPITAL COST FOR CONVERSION TO HEAT PUMPS

A. Central Systems

There are 4.8×10^6 households which may be converted to central heat pumps.[1] Assuming the average installed cost at 4000 to 5000[13], the capital cost is:

($4000 to $5000) (4.8×10^6) = \$19 to \$24 $\times 10^9$.

B. Unitary Heat Pumps

There are 8.6×10^6 households which may be converted to heating with unitary heat pumps[1]. Assuming four units are required per household, and installed cost for each unit is 1400 to 1600, [5] the capital cost is:

(8.6×10^6) (4) (\$1400 to 1600) = \$48 to \$55 $\times 10^9$.

C. Domestic Hot Water Heaters

At an average installed cost of \$1000 (\$800-\$1200 range)[14] and 5×10^6 units to be converted,[15] the capital cost is \$5 $\times 10^9$.

The total capital cost for residential sector is thus estimated to be \$72 to \$84 billion. Assuming an additional 20 percent for the commercial installation, the capital cost for heat pumps in buildings without any electric line changes is \$86 to \$101 billion. It is assumed that one-half of the households will require an additional expenditure of \$350 for new main electric line connections bringing the total cost to \$88 to 103 billion.

Based on 880,000 boe/d to be replaced, capital cost is thus \$100,000 to \$117,000 per boe/d.

EXHIBIT B-1-3

TIME REQUIRED FOR MANUFACTURING OF HEAT PUMPS

The following analysis assumes conversion of all 13.4×10^6 households heating with oil/kerosene to heat pumps which may be conservative based on Exhibit B-1-1 which estimates that only two-thirds could convert.

A. Central Heat Pumps

In 1981, 505,000 central heat pumps were installed in the U.S.[16] In general, three central air conditioning systems are installed for each central heat pump.[17] Manufacturers of central air conditioning units can easily convert to manufacturing heat pumps since both can orient their products toward cold climate usage, or heating only heat pumps.

Assuming that the manufacturing facilities were operating at 70 percent of capacity, the total manufacturing capacity would be 2.89×10^6 units/yr (= 505,000 x 4/0.70). If 50 percent of this capacity is used for manufacturing central heat pumps, the required 4.8 million heat pumps could be manufactured in four years including 20 percent allowance for heat pumps in commercial installation.

B. Unitary Heat Pumps

In 1981, 0.5×10^6 unitary heat pumps and 3.7×10^6 room air conditioning units were installed.[17] Based on a 70 percent industry wide capacity factor, and assuming that 50 percent of the manufacturing capacity is directed towards unitary heat pumps, the 34 million heat pumps required would need about 11 years. Thus to achieve the market penetration in five years, new manufacturing capacity of about 4 million units per year would be required. This may be an initial constraint but not one that will last for more than one or two years.

7. References

(1) "Residential Energy Conservation Survey-Housing Characteristics, 1980," DOE/EIA-0314, June 1982, Table 27, pg. 124.

(2) "Systems," ASHRAE Handbook and Product Directory, 1980, Ch. 11, pg. 11.4.

(3) Ibid., Ch. 46, pg. 46.5.

(4) Memo from Tom Bull to N. Naismith and D. Strom. "Rationale for Deemphasizing Certain Types of Petroleum Uses as Candidates for Replacement During an Oil Short-Fall," October 14, 1982, Table 2.

(5) Nervina, E. (Cassidy-Powdell, a Singer Co. representative) personal communication on November 17, 1982.

(6) Electricity Costs per Kilowatt-Hour by Sector," Energy User News, August 30, 1982, pg. 13.

(7) Draft Scope of Work, OTA US 82.8 Oil Replacement Analysis, pg. 4.

(8) Catalog of Energy and Utility Loads, DOE No. E(40-1)-5036, June 1978, Table 17-4, pg. 251.

(9) Report of Member Electric Systems of the New York Power Pool, 1982, Vol. No. 1, pg. 39, Exhibit 4.

(10) "Electric Power Supply and Demand, 1982-1991," Regional Reliability Councils of NERC, Aug. 1982.

(11) Letter R.M. Maliszweski (American Electric Power Service Corporation) to T. Bull (Office of Technology Assessment) of February 9, 1983.

(12) "Residential Energy Conservation Survey: Housing Characteristics, 1980," DOE/EIA-0134, June 1982, Table 16, pg. 75.

(13) Johnson, S. (Flanders Sheet Metal Co., Freeport, N.Y.) personal communication, November 17, 1982.

(14) Soman, Shiva (Millander-Wilke, Inc.) personal communication, November 10, 1982.

(15) "Residential Energy Conservation Survey: Housing Characteristics, 1980," OP. CIT, Table 19, pg. 91.

(16) Szymczyk, L. (ARI) personal communication November 17, 1982.

(17) Mahoney, T. (ACHR News, Troy, Mich.) personal communications on November 10 and 22, 1982.

(18) "Systems," ASHRAE Handbook and Product Directory 1980, Ch. 43.

B. ELECTRICITY IN BUILDINGS

PART 2: ELECTRIC RESISTANCE HEATING

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1. Introduction

2. Commercialization Assessment

3. Oil Replacement Potential

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5. Non-institutional Constraints

6. Institutional and Regulatory Constraints

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B-2-1 Cost for Conversion to Resistance Heaters

B-2-2 Time Required for Manufacturing Resistance Heaters

1. Introduction

The substitution of electric power for fuel oil heating in residences involves the abandonment of the steam and hot water heating systems for portable electric heaters which will be used generally only in those rooms which are occupied at the time.* The substitution of electric power for fuel oil heating in commercial establishments involves the abandonment of the steam and hot water heating systems for attached electric baseboard, convectors and unit heaters. Selective zone heating is mostly inapplicable in commercial facilities. For domestic hot water, only the oil fired domestic water heater must be replaced with an electric hot water heater. The remainder of the hot water plumbing system will generally remain intact.

Implicit in this substitution is the understanding that fuel oil will not be used in generating the electic power.

2. Commercialization Assessment

The technology for these installations has been in successful operation for many years. The equipment is guaranteed and the installation is subject to government code requirements.

This conversion can be accomplished within the five year time frame, and, may be very appropriate for outlying non-urban areas, where alternative distribution of NG would be costly and time-consuming.

The conversion from oil heating to electric resistance heating cannot be applied until the bulk of the fuel oil burning electric power capacity has been converted to other fuels.

3. Oil Replacement Potential

The oil replacement assessment is the anticipated non-residual oil usage for heat and domestic hot water, minus the LPG usage for this market. This is as follows:

$1.175 \times 10^6 - 0.295 \times 10^6 = 0.88 \times 10^6$ bbl/day [1].

Because of selected heating achieved via domestic portable heaters, the peak power requirement is less than that for the heat pump option where the electric resistance heating

Note
*Implicit in this substitution is the understanding that fuel oil will not be used in generating the electric power.

capacity is sized to the heat pump capacity. With portable electric resistance heaters, the total capacity per household is assumed to be one-third of that required for the fully sized heat pump option, i.e., 7,000 Btu/hr or 2 kW for each of 3 heaters. For 13.4 x 10^6 households the total power required is 40,000 MW assuming 50 percent of the units are on at once. Adding 16,000 MW and 24,000 MW for hot water heating and commercial facilities (see Appendix B-1), respectively, brings the total to 80,000 MW. With an available power of 100,000 MW (see Appendix B-1) all of the 880,000 bbl/day of oil could be displaced by electric resistance heating. However, to verify this apparent adequacy of electric generating capacity will require a much more detailed analysis. Such an analysis is being conducted separately by OTA.

4. Costs

The average price for residential/commercial electric power is about 6.9¢/kW-hr.[2] This equates to fuel oil as follows:

$$\frac{(\$0.069/\text{kW-hr})(5.5 \times 10^6 \text{ Btu/bbl oil})}{3413 \text{ Btu/kW-hr}} = \$111/\text{boe}.$$

Taking into account the average inefficiency of fuel oil combustion yields ($111)(0.67) = $74/boe fuel charge.

The cost of installation of electric heaters and domestic hot water heaters in place of oil based heaters is $20 x 10^9 or $23,000 per boe/d. (See Exhibit B-2-1.) At a fixed charge rate of 20 percent this is equivalent to a fixed charge of $13/boe.

Thus, the annual cost of conversion to electric resistance heating is $87/boe.

5. Non-institutional Constraints

The skilled labor force of electrical workers to install resistance heating on the scale required for commercial installations does not exist at the present time. A training period of about six months would be needed to train an electrician with a license limited to these activities only. This does not represent a constraint.

The manufacture of resistance heaters and water heaters would be a constraint on this option at the beginning of the five year period but would catch up soon to the availability of skilled electricians (see Exhibit B-2-2). The basic constraint is the availability of non-oil based electric generating capacity.

This is a labor intensive modification particularly for commercial installations. However, in a crisis, it constitutes one of the important prospects which must be considered, if only for a part of the solution.

6. Institutional and Regulatory Constraints

The manufacture and installation of the electric components is very much regulated by codes and standards. These will have to be complied with. However, where a licensed electrician may have been required in the past, a limited license may be sufficient in the event of a crisis.

EXHIBIT B-2-1

COST FOR CONVERSION TO RESISTANCE HEATERS

A. Domestic Portable Heaters

In the U.S. there are 13.4×10^6 households which heat with oil or kerosene [9]. Assume that each household will require 3 portable electric heaters. At a price of $50 per heater[10] plus $350 additional for main electric line connections required in about half the installations, the capital cost will be:
$(3)(\$50)(13.4 \times 10^6) + (\$350)(13.4 \times 10^6)(0.50)$ or equal to $4.4 billion.

B. Domestic Hot Water Heaters

At $1000 installed cost[10] per heater and 5 million installations (see Appendix B-1), the capital cost will be $5 billion.

C. Commercial Installations

For commercial installations, while some unit heaters and convectors will be required, most of the heating will be done with attached baseboard heaters. Assuming that the number of such installations is 40 percent of domestic portable heaters, and that the average cost per unit is $600 including a 20 percent allowance for main electric line connections[11], the capital cost will be:
$(3)(13.4 \times 10^6)(0.40)(\$600)$ or $9.7 billion.

D. Total Cost

The total cost for this option is thus estimated to be approximately $20 billion or based on 0.88 million boe/d replaced, the capital cost is $23,000/boe/d.

EXHIBIT B-2-2

TIME REQUIRED FOR MANUFACTURING RESISTANCE HEATERS

A. In 1980, 13.4×10^6 portable electric heaters were shipped[12]. Assuming the manufacturing facilities were operating at 70 percent capacity, the required 3 x 13.4 million heaters could be manufactured in about 2 years.

B. In 1980, 2.8×10^6 fixed electric baseboard heaters were shipped.[12] Assuming a 70 percent capacity factor for these facilities, the required 3 x 13.4 x 0.4 million units for commercial installations could be manufactured in about 4 years.

7. References

(1) Memo from Tom Bull to N. Naismith and D. Strom. "Rationale for Deemphasizing certain Types of Petroleum Uses as Candidates for Replacement During an Oil Short-Fall," Oct. 14, 1982, Table 2.

(2) "Electricity Costs per Kilowatt-Hour by Sector," Energy User News, Aug. 30, 1982, pg. 13.

(3) Draft Scope of Work, OTA US 82.8 Oil Replacement Analysis, pg. 4.

(4) Catalog of Energy and Utility Loads, DOE No. E(40-1)-5036, June 1978, Table 17-4, pg. 251.

(5) Report of Member Electric Systems of the New York Power Pool, 1982, Vol #1, pg. 39, Exhibit 4.

(6) "Electric Power Supply and Demand, 1982-1991," Regional Reliability Councils of NERC, Aug. 1982, Table 12, pg. 33.

(7) Ibid, Table 18, pg. 44.

(8) "Residential Energy Conservation Survey: Housing Characteristics, 1980," DOE/EIA-0134 of June 1982, Table 16, pg. 75.

(9) Ibid, Table 15, pg. 71.

(10) "1982 Buying Guide Issue - Portable Electric Heaters," Consumer Reports, pg. 162.

(11) Shiva Soman (Millander-Wilke, Inc.), personal communication, November 10, 1982.

(12) "Selected Heating Equipment," MA34N, U.S. Census Bureau.

C. COAL AND/OR WOOD IN BUILDINGS

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1. Introduction

2. Commercialization Assessment

3. Oil Replacement Potential

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5. Non-institutional Constraints

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C-1 Cost of Conversion of Buildings to Wood or Coal

1. Introduction

The substitution of wood and coal for fuel oil (FO) in residential and commercial heating applications involves the addition of a new dual fuel (coal/wood) boiler or furnace to the existing installation, whether boiler or hot air distribution. The existing boiler, distribution ducts and piping, flue and chimney would be retained for use with the add-on equipment.[1] The existing equipment may continue to operate as a back-up or when the occupants are away for an extended period of time. This amount of FO usage is negligible and will not be considered in the analysis.

Domestic hot water systems which are oil-fired will tie into the new add-on wood/coal boiler. This should account for substantially all of the domestic hot water heating with FO, since hot air systems are most likely to use gas or electric heating for domestic hot water.

2. Commercialization Assessment

The technology for these solid fuel add-on furnaces is well established and is being increasingly applied, especially in areas where wood is readily available. Guarantees and warranties are provided as a matter of course. All conversions to wood/coal in our analysis are for central heating systems.

For the crisis scenario we will assume 20 percent replacement of existing equipment is required,[2] and the remainder will be add-on installations. Those that require replacement may be assumed to be coal-fired, since coal will provide, by far the greater part of the FO replacement.

The manufacture and use of coal-fired boilers and furnaces is a very old technology, thus there is no need for a description in this report. This type of equipment may be furnished with an automatic stoker so that back-up of equipment while occupants are away does not constitute a detriment.

No strategic material is involved in this change-over of equipment and thus no bottlenecks would result.

3. Oil Replacement Potential

In 1981 approximately 0.8 quadrillion Btu of fuel wood was consumed in households in the U.S. [15] Essentially all of this consumption was for space and hot water heating since wood used for cooking makes up a very small percentage of household wood consumption. Commercial building fuel wood consumption is not significant being only 0.014 quadrillion Btu in 1979. Historically, in households only 10 percent of the wood is consumed in central heating systems using furnaces, which operate at approximately 50 percent efficiency. The balance are wood stoves which have an efficiency of 25 to 50 percent, which is mostly dependent on whether the stove has a circulator. Using an average of 35 percent efficiency for stoves and 70 percent efficiency for oil furnaces, the current oil displacement by residential wood firing is approximately 207,000 bbl/d

$$=[((0.1 \times 0.5)+(0.9 \times 0.35))(0.8 \times 10^{15}/5.5 \times 10^{6} \times 365 \times 0.7)].$$

The oil replacement potential for wood and coal is constrained by the following:

a. Adequacy of good quality wood and anthracite coal containing less than 1 percent sulfur.

b. Transportation of wood and coal to individual homes.

c. Physical space for wood and coal storage at individual homes.

d. Environmental impact from increased particulate emissions and ash disposal.

For screening purposes, it is assumed that 50 percent of distillate oil and kerosene used in buildings (i.e. 440,000 bbl/d from Appendix A) could be replaced either by wood or coal.

4. Costs

The average U.S. price of seasoned wood delivered for residential use is estimated at $100/cord in 1982. Air dried, seasoned wood contains 12 to 15 percent moisture and delivers about 85 percent of the total Btu's as heat, reducing the net heating value of air dried wood to 20.7 million Btu per cord.[15] This results in a wood price of $4.83/MMBtu. This cost can be reduced appreciably if the consumer is willing to cut, gather and split wood or cut and split delivered lengths of wood.

The retail price of anthracite coal delivered and sized for home use is estimated at $4.00/MMBtu.[16]

The capital cost for conversion to wood or coal is estimated to be $21,000/boe/d, while the annual costs are estimated to be $48/boe and $40/boe for wood and coal, respectively. (See Exhibit C-1.)

5. Non-institutional Constraints

No highly skilled labor is required for this consumer conversion. In Wisconsin most of the installations are performed by the owner, and the finished work is inspected by the utility.[11] A shortage of semi-skilled labor can be corrected in a reasonably short time by establishing training through public utilities as well as other training facilities. This does not represent a constraint.

Sufficient facilities for manufacturing of the furnaces and boilers exist to keep up with the rate of installation. Assuming plants which manufacture boilers and furnaces may easily convert to the add-on equipment manufacture, and if necessary, can go to multiple shifts, supply of the units would not constitute a critical time element in this conversion.

Transportation of wood and coal to individual buildings and physical space limitations at individual buildings could pose major constraints for the widespread use of this option.

6. Institutional and Regulatory Constraints

The environmental impact is an important consideration in this substitution of fuels. For coal, both SO_2 and particulates would be increased; for wood the particulates would be increased.

The effects of coal substitution for # 2 FO assuming 0.7 percent S in anthracite,[6] and 0.3 percent S in #2 FO[14] would cause an increase of SO_2 of (0.7/0.3) x (0.70/0.60) or 2.7 times the present emission from residential and commercial heating. The particulate increase would be even greater. However, the total effect in the communities would not be as great as implied by these figures because these emissions would represent only a fraction of the already generated emissions from other sources.

It is possible that some variances may be required in some communities if a full scale substitution is implemented.

In many locations, where there are boiler connections to be made, a licensed plumber must be in charge of the piping. However, he may be the only one in a large organization which performs many such conversions. Furthermore, in a crisis situation, limited licenses may be issued to skilled people who have received enough specialized training, to then be capable of performing the conversion.

EXHIBIT C

COST FOR CONVERSION OF BUILDINGS TO WOOD OR COAL

A. The average cost of conversion varies somewhat but a weighted average figure for a conversion that does not entail replacing a boiler is about $1,000 [11]. To run a piping or ductwork connection could cost an additional $600 for a total of = $1,600.

The average cost when the boiler must be replaced is about $3,000 [12].

B. Of the 5 million conversions (see Appendix A), assume 80 percent entail use of existing boilers and 20 percent require new boilers.[2] The capital cost of these conversions is as follows:

$0.80 \times 5 \times 10^6 \times 1600$	=	$6.4 billion
$0.20 \times 5 \times 10^6 \times 3000$	=	$3.0 billion
Total Capital Cost	=	$9.4 billion
Oil Replaced	=	440,000 boe/d
Capital Cost, $/boe/d	=	21,000

C. Annual cost for these conversions is estimated as follows:

Capital Charge	=	$11.5/boe
Fuel	=	$33.8/boe for wood(*)
	=	$25.7/boe for coal(**)
Total (***)	=	$48.3/boe for wood
		$40.2/boe for coal

(*) Based on $4.83/MMBtu for delivered wood, and 55 and 70 percent efficiency for wood and oil combustion, respectively.

(**) Based on $4.00/MMBtu for delivered coal, and 60 and 70 percent efficiency for coal and oil combustion, respectively.

(***) Including an allowance of $3/boe (equivalent to about $100/year/home) for storage and ash disposal.

7. References

(1) Woodchuck Bulletin, Eau, Wisconsin.

(2) Martin Gitten (Consolidated Edison, New York) personal communication October 20, 1982.

(3) Memo from Tom Bull to N. Naismith and D. Strom. "Rationale for Deemphasizing Certain Types of Petroleum Uses as Candidates for Replacement During an Oil Short-Fall," October 14, 1982, Table 2.

(4) "Residential Energy Conservation Survey: Housing Characteristics, 1980," DOE/EIA-0134 of June 1982, Table 16, pg. 75.

(5) Memo from T. Bull to N. Naismith and D. Strom. "Potential Wood Energy," October 8, 1982.

(6) Marks. "Mechanical Engineers' Handbook," 6th Edition, Table 1, pg. 7-3.

(7) "Statistical Abstracts of the U.S.," 102nd Edition, U.S. Dept of Commerce, Bureau of Census, 1981.

(8) "Distributed Solar Energy System -- Wood Combustion Systems for Process Steam and On-site Electricity," MTR 79W00021-04, The MITRE Corp., Vol. IV.

(9) "Systems Descriptions and Engineering Costs for Solar Related Technologies, Biomass Fuels Production and Conversion Systems," MTR-7485, Vol. IX, The MITRE Corp., June 1977, pg. 41.

(10) "Comparative Fuel Pricing Trend Line," Coal Week, June 7, 1982, pg. 7.

(11) Carlson, S., (Woodchuck House Heating Systems) personal communication, November 24, 1982.

(12) Steve Renna (Brooklyn Union Gas Co.) personal communication, October 20, 1982.

(13) "Residential Energy Conservation Survey," Op. Cit. Table 19, pg. 87.

(14) Exxon DG-1E Data Sheet - Heating Oil for Domestic Boilers, January 2, 1973.

(15) "Estimates of U.S. Wood Energy Consumption from 1949 to 1981," DOE/EIA-0341, August 1982.

(16) Westerstrom, L. (U.S. Department of Energy, Washington, D.C.) personal communication, December 1982.

D. COAL IN ELECTRIC UTILITIES AND INDUSTRIES

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1. Introduction

2. Description

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D-1 Utility Coal Conversions

D-2 Capital Cost Range for Coal Conversion ($/kWe)

D-3 Capital Cost of Coal Conversion ($/bbl/day)

D-4 First Year Coal Conversion Costs ($/bbl oil equivalent)

1. Introduction

Existing oil-fired power plants can be converted to direct coal firing by either conventional conversion or erecting a "slide-along" coal-fired boiler. Conventional conversion, when applied to oil-fired plants originally designed to burn coal, is termed coal reconversion. Another potential option that has not yet been demonstrated on a commercial scale is micronized coal firing.

2. Description

Oil-fired units that are candidates for conversion to coal firing can be broadly classified into two categories:

a. Plants designed originally to burn coal or with a future coal-burning capability

b. Plants designed to burn oil and in some instances, with the ability to burn natural gas as an alternate fuel.

For those units originally designed to burn coal, reconversion to coal firing entails modifications in several general catagories:

a. Boiler Modifications

These will vary from boiler to boiler, but generally should not be too extensive, particularly if the coal type selected is close to the original coal specifications. Also derating should be small or moderate in many cases.

b. Air Pollution Control Equipment

This includes, as a minimum, a new electrostatic precipitator (or baghouse) or upgrading the existing precipitator. A flue gas desulfurization (FGD) system may be required, depending on applicable sulfur oxide regulations.

c. Ash, Reagent and Sludge Handling Systems

Ash handling includes bottom ash and fly ash handling and disposal systems. Units with FGD require a reagent handling system and sludge handling and disposal.

d. Coal Handling

This could prove to be costly if the previous coal handling system has been demolished or is in a very poor state of repair.

e. Miscellaneous Modifications

This category includes, for example, waste water treatment related to ash handling, coal pile run-off and so forth.

Conversion to coal firing of units originally designed to burn oil is more complex than coal reconversion, particularly with regard to the following:

a. Boiler Modifications

Because the design of an oil fired boiler is significantly different than a coal-fired boiler with regard to furnace volume, heat release rates, exit gas temperatures, gas velocities and so forth, even extensive and costly modifications cannot insure that conversion to coal can be accomplished without a potentially significant derating. The actual derating depends on many factors and varies from boiler to boiler. In addition, pulverizers and coal silos (or bunkers) have to be added to convert an oil fired boiler to pulverized coal firing.

Provisions for bottom ash disposal also have to be made. Other modifications are similar to those discussed for coal-liquid mixture firing, e.g., burner and windbox modifications (see Appendix E).

b. Space Considerations

Oil fired power plant sites may not have space available for major systems related to coal burning such as coal handling and storage and ash handling and disposal. The addition of a new electrostatic precipitator could pose a problem for a site with severe space limitations. Finally, if appropriate regulations necessitate the use of an FGD system, additional space would be required. Lack of adequate space is a major consideration that could limit conversion of oil-fired units to coal firing.

It should be emphasized that proper coal selection is of paramount importance for any project involving

conversion to pulverized coal firing due to the close relationship that exists between boiler performance and ash characteristics, particularly to ash fusion temperature.

In some instances, new "slide-along" coal-fired boilers could be employed to convert an oil-fired facility to coal-firing. A "slide-along" boiler is simply a new coal-fired boiler erected close to the existing oil-fired boiler and later "tied-in" to the existing steam lines. For electric utilities the "slide-along" boiler would be a pulverized coal-firing unit while for industrial/commercial applications, fluidized bed combustion units are a possibility. This "slide-along" approach can only be justified if the following criteria are met:

1) Sufficient space is available for the slide-along boiler and the length of the main steam and reheat steam piping is reasonable.

2) The remaining economic life of the non-boiler portion of the plant is reasonably long enough to economically justify the conversion.

3) The overall cost of this approach is less than direct conversion, taking into account the economic impact of derating.

Micronized coal, also known as ultrafine or superfine coal, has been the subject of recent experiments intended to demonstrate that coal can be burned directly in an oil-fired boiler without the need of an oil and/or water based slurry. A typical micronized coal size is 90 percent less than 10 microns. Pulverizing coal to this size is quite energy intensive and presents potential handling problems due to the possibility of explosion of very fine coal dust. Early experimental evidence indicates that micronized coal burns very much like residual oil in a boiler. However, it is not expected that micronized coal will be a commercial technology by 1985.

3. Commercialization Assessment

Conventional conversion to pulverized coal firing and the erection of slide-along boilers are both established technologies. In the last several years, seven utilities have completed the conversion of 20 units, with a total generating capacity of 6000 MW[1]. Table D-1 summarizes coal conversion projects that have been completed, those that are definitely planned, and those that are under consideration.

The fact that only a relatively small number of conversions have been completed or even considered is not a reflection of the technology readiness or integrity, but rather is due to a complex array of economic, financial and regulatory considerations.

TABLE D-1

UTILITY COAL CONVERSIONS

	COMPLETED CONVERSIONS	DEFINITELY PLANNED CONVERSIONS	CONVERSIONS UNDER CONSIDERATION
Number of Utilities	7	9	11
Number of Units	20	32	36
Total Capacity (MW)	6000	3700	9000

Note - Total Oil-Fired Utility Capacity is 165,800 MW of which 27,700 MW is oil/gas dual fuel.

4. Oil Replacement Potential

The oil replacement potential for coal conversion of utility and industrial/commercial boilers is assigned the same value as that estimated for coal-water mixtures in Appendix E. This is based on the following:

a. Coal capable boilers will be attractive for switching to either fuel (i.e. coal or coal water mixture) and the choice will be based on site specific conditions such as available space or condition/existence of solids handling equipment.

b. Switching to either coal or coal-water in oil units without coal capability involves consideration of many similar variables such as derating, boiler configuration, and equipment age.

It is not suggested that the attractiveness of each individual boiler for switching to either fuel is identical but rather that with similar criteria and bases for switching the advantage of one over another in terms of oil replacement is slight when the entire boiler population is considered. Thus, the oil replacement potential for conversion to coal firing is estimated to be 713,000 boe/d divided into 462,000 boe/d for utilities and 251,000 boe/d for industrial/commercial facilities.

5. Costs

The costs for conversion to coal firing can vary widely depending on a number of factors. For example, if an FGD system is required, the capital cost of a conversion could easily be twice that of a plant which does not require FGD. Similarly, a slide-along boiler option would be more costly than modifying an existing boiler, but it offers the advantage of insuring that full capacity can be retained. Other factors include the nature and extent of modifications or additions to the coal receiving, handling and storage systems and ash handling and disposal systems. Because of the wide variation in costs, it is preferable to illustrate the range of capital costs, including separate ranges for utility plants with and without FGD. Such data is presented in Table D-2 in 1982 dollars.

Note that it is assumed that industrial/commercial boilers are converted only if FGD were not required. This is a reasonable assumption since these facilities can utilize low sulfur coals for maintaining compliance with ambient SO_2 regulations. The low end of the cost range for utility plants reflects coal designed units with coal-related

facilities relatively intact and thus would require the least investment. The high end of cost range for utility plants reflects oil-designed units for which a slide-along boiler and other equipment associated with coal burning have been added. It is important to note that in both cases the full capacity of the original unit can be achieved. However, modification of an oil-designed boiler, while less costly than a slide-along boiler, would be in conjuction with a potentially large derating.

The cost range for industrial and commercial units is wider than for utility plants because of the wider variation in boiler sizes for the industrial and commercial units.

Table D-3 illustrates the cost of coal conversion in 1982 dollars per barrel per day for the utility and industrial/commercial sectors. The results were based on the following assumptions:

a. For utility plants with and without FGD, an average cost of $450/kW and $250/kW is employed, respectively. These values are less than the medians of the data in Table D-2, reflecting the assumption that coal conversion would be performed for those units which were most economical, including many units with coal-designed boilers.

   For utility units over 50 MWe in size there is a total capacity of 30,165 MW (220 units) of coal-designed boilers currently burning oil.[4] Units that are oil designed and currently burning oil can be classified into two types according to their configuration. Type 1 is similar to a coal-designed boiler configuration and represents 41,131 MW (171 units) of capacity out of a total of 63,279 MW (245 units) of oil designed capacity over 50 MW in size. Thus, the total capacity of units most economical for conversion to coal is 71,296 MW (391 units) out of a total of 93,600 MW over 50 MW size. A 50 percent market penetration of the total population over the 50 MW size is assumed in arriving at the oil replacement potential.

   The cost data for the utility conversions in Table D-2 are based on engineering, design and estimating work performed by G&H for utility clients in the Northeast. The costs included boiler modifications, new or upgraded precipitators, FDG systems, solids handling systems and balance-of-plant materials and labor including any required waste water treatment. Because of site specific conditions such as boiler type, equipment condition and environmental regulations the cost

emphasis among the above modifications will vary from site to site.

b. For industrial/commercial plants, an average cost of $500-700/kW is employed. This range is slightly in excess of the median value from the data in Table D-2, reflecting the assumption that all of the industries wishing to convert to coal would replace existing facilities with new coal-fired boilers. The costs are based on G&H in-house data from major boiler manufacturers for slide-along plants, which vary from $60 to $90 per lb of steam per hour.

c. The market penetration and oil replacement data is assumed to be the same as that presented for coal-water mixtures in Appendix E.

TABLE D-2

CAPITAL COST RANGE FOR
COAL CONVERSION
($/kWe)

	Utility	Industrial/Commercial
Without FGD	150 - 450	250 - 900
With FGD	275 - 650	Not Considered

TABLE D-3

CAPITAL COST OF COAL CONVERSION
($/bbl/day)

Utility*	Industrial/Commercial**
25,300 to 45,500	37,000 to 52,000

*Assumes use of existing boilers, modified to burn coal.
**Assumes new "slide-along" boilers.

Table D-4 illustrates the first year costs of coal conversion in terms of dollars per barrel of oil equivalent. The capital charges are based on the capital costs used to derive the data in Table D-3. For utility conversion, the total capital costs are 11.7 to 21 billion dollars to replace 462,000 boe/d. Using a fixed charge rate of 20 percent the first year fixed charge is 13.9 to 24.9 $/boe. For industrial/commercial conversions the total capital costs are 9.3 to 13.1 billion dollars which translates to a fixed charge of 24.4 to 28.5 $/boe.

The fuel costs in Table D-4 are based on an estimated delivered cost of $2.25 per million Btu for both utility and industrial/commercial options. In actuality, coal costs could vary based on coal specifications, volume and, perhaps most importantly, transportation costs. For the purpose of this initial study phase, the variation of these factors is neglected.

The O&M costs are derived from Gibbs & Hill in-house data for utility and industrial coal-fired power plants.

TABLE D-4

FIRST-YEAR COAL CONVERSION COSTS

($/bbl oil equivalent, (boe))

	UTILITY	INDUSTRIAL/COMMERCIAL
Capital Charges	13.9 to 24.9	24.4 to 28.5
Fuel	12.4	12.4
O&M	1.1	1.6
Total	27.4 to 38.4	38.4 to 42.5

6. Non-institutional Constraints

The non-institutional constraints for conversion to direct coal firing are similar in many respects to those discussed for COM and CWM. There is one important difference, however, adequate space for coal handling and storage facilities is an absolute necessity for direct coal firing whereas COM or CWM can be prepared offsite and utilized with little or no need for extra fuel handling and storage facilities.

The above discussion illustrates the situation where a particular plant may lend itself to COM or CWM conversion but not to conventional conversion to coal firing. The reverse situation is also possible, i.e., direct coal conversion is more attractive for certain plants than COM or CWM. The plants that fall into this category include various units which originally burned coal and later were converted to oil firing but which retained their coal handling systems and other provisions for coal burning. These plants would normally have lower conversion costs than other oil-fired units and would be the most likely candidates for early conversion. In fact, the units described in Table D-1, which are in various stages of coal conversion, demonstrate that coal conversion is more attractive at present than options like COM or CWM.

Depending on the type of original design, whether oil or coal, and the condition of equipment, the following may present constraints in converting approximately 300 utility units: new electrostatic precipitators, new fans, soot blowers, pulverizers, modification of bottom ash hopper and modification and replacement of economizer tubing. In terms of skilled labor availability, the boiler modifications above could be a constraint. For industrial installations the requirement for hundreds of new coal-fired boilers and associated precipitators would constrain these conversions.

In a crisis situation where lead times are a major concern, coal conversion could be seriously hampered if FGD systems are to be required. This is due to the relatively long lead times of 24 to 30 months for equipment procurement and installation.

7. Institutional Constraints

The air emission constraints discussed for COM and CWM would, in general, apply to coal conversion also (see Section E.7). In particular, units converting to coal firing would not be subject to Federal NSPS regulations, but would be subject to a variety of state regulations. State regulations regarding sulfur oxide emissions represent the single most significant

obstacle to coal conversion. The power plants that have converted to coal firing to date have done so without the need to install FGD systems. There appears to be a general consensus in the electric utility industry that conversion to coal will be resisted if FGD is a mandatory feature of the conversion. Some conversions to low-sulfur coal will produce less SO_2 emissions than with current oil burning and utilities reason that FGD systems should not be required on this basis. Most importantly, some FGD systems have had poor reliability records which has forced utilities to burn premium fuels, generating electricity at a higher rate than allowable and, thus, decreasing their rate of return on equity. Increases in generating costs, caused by poor reliability, mean that very few utilities make the allowable rate of return. Also, because the FGD system has the longest lead time for coal conversions and existing units have a finite remaining life, conversion investment must be amortized over shorter time periods resulting in upward pressure on electricity cost.

In order to address the environmental regulations in a manner which permits using the fuel savings to finance the pollution control equipment, the EPA has issued delayed compliance orders that allow a plant to burn coal initially without full compliance with environmental regulations. At New England Electric System's Salem Harbor Station which has been converted to coal-firing such a delayed compliance order has been invoked.[3] Some of the fuel savings are passed along to the utility's customers, but the bulk of the savings are used to pay for added pollution control equipment, in this case a set of larger electrostatic precipitators.

In addition to environmental regulations, other Federal regulations, like the Fuel Use Act of 1970 (FUA), have influenced conversion to coal. The provisions of FUA include among other things, the issuance of "prohibition orders" to certain power plants and major fuel burning installations (MFBI) which constitutes the first step in a series of regulatory actions designed to replace oil and natural gas with alternative fuels, particularly coal. While the provisions of the FUA have historically been difficult to enforce, it should be noted that various states may have similar programs which provide greater impetus to convert than the FUA.

A potentially significant constraint to utility coal conversion is the method of capital recovery allowed and the issue of "construction work in progress" (see Section E.7 for discussion).

Northeast Utilities (NU) has pioneered an innovative method of financing the conversion of its Mt. Tom Unit No. 1 in Massachusetts which may become a model for other electric utilities seeking to ease the financial burden of coal conversion.

The Northeast Utilities' method, known as "Oil Conservation Adjustment," allows NU to retain two-thirds of the fuel savings until the capital expense is recovered which is expected to take two years. The ratepayers get one-third of the fuel savings for the first two years and the full amount of the savings thereafter. While this financing method does encourage coal conversion, state public utility commissions would probably have to rule on each application on a case-by-case basis.

8. References

(1) "Coal conversion Trend Shifts into High Gear," Electric Light and Power, September 1982.

(2) "Converting Power Plants to coal," Power Engineering, December 1980.

(3) The Energy Daily, August 5, 1982.

(4) DOE/FE/53179-01, "Survey of Oil-Fired Utility Boilers," U.S.DOE., July 1980.

E. COAL-LIQUID MIXTURES

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E-3 Schematic Flow Diagram - Coal-Water Mixture Preparation Plant

1. Introduction

Coal-Oil Mixtures (COM), Coal-Oil-Water Mixtures (COWM) and Coal-Water Mixtures (CWM) have the potential to displace substantial amounts of residual fuel oil used in utility and industrial sectors. These two technologies, which comprise various processes, have been demonstrated in either pilot/demonstration plant test or in actual commercial operation. Recently there have been a number of conceptual efforts underway related to coal-liquid CO_2 and coal-methanol mixtures. Technologies for these mixtures are being studied primarily as alternatives to long distance coal transportation. Given the conceptual nature of these technologies, they are not included in our analysis.

2. Description

COM represents a commercially proven technology for utilizing coal in an oil-fired boiler. COM is a particularly important option for oil-fired boilers for which conversion to direct coal firing is not a feasible alternative. An example of a COM is a 50/50 (by weight) mixture of bituminous coal and residual fuel oil. The coal would supply approximately 40 percent of the Btu's of the COM. To date, bituminous coal has been employed in essentially all COM processes. It should be noted that if a subbituminous coal were employed instead of a bituminous coal, the Btu content of the COM would be reduced due to the lower heating value of the subbituminous coal.

COM's can be produced by several processes. In some processes, the coal is conventionally pulverized, i.e., 80 percent passing through a 200 mesh screen, and mixed with fuel oil. This size consist is sometimes referred to as "standard grind." A chemical additive is effective in inhibiting premature settling of the coal. Also, mechanical agitation in mixing and storage tanks is used in lieu of, or in conjunction with, chemical additives to inhibit settling. A typical schematic flow diagram is shown in Figure E-1.

Another method to inhibit settling, and in general to make the COM behave very much like a heavy fuel oil, is to reduce the size of the coal to an "ultrafine" size, i.e., 98 percent passing through a 325 mesh screen. Ultrafine coal can be produced in conventional mechanical pulverizers, although the process is more energy-intensive than for standard grind pulverization. A typical schematic flow diagram is shown in Figure E-2.

COM's may be prepared onsite or at a remote (i.e., offsite) facility and transported in essentially the same manner as

heavy fuel oil. Onsite and offsite preparation have certain advantages and disadvantages. Onsite preparation would probably be limited to electric utilities and large industrial facilities, due to economic considerations and space limitations.

Similarly, offsite preparation is quite attractive to smaller consumers, namely small or medium-size industrial facilities, who lack sufficient space or capital resources to build an onsite COM preparation facility.

There are fundamentally two groups of oil-fired boilers in which COM would be employed. The first group includes boilers designed solely for oil firing. The second group includes boilers originally designed for coal firing and subsequently converted to oil firing. The latter group of boilers is generally more amenable to the use of COM, and usually allows a greater leeway in the selection of coal for the COM. On the other hand, the proper selection of coal characteristics, including ash fusion temperature, abrasiveness of the ash and slagging and fouling tendencies, is of great importance for boilers designed solely for oil firing. This is mainly due to the fact that oil-fired boilers are generally designed for higher flue gas velocities, thus coal ash in a COM could cause tube wear and inhibit heat transfer across the convection surfaces of the boiler. In order to minimize the adverse effects of coal ash on performance, beneficiated or high quality coals are used in the production of COM.

Boiler modifications are required to burn COM and they vary greatly from one boiler to another. Some boilers may require that the furnace bottom be modified to include a suitable bottom ash hopper and that a pit be constructed beneath it to facilitate bottom ash removal. Certain boilers may require an increased tube spacing in the economizer, superheater and reheater (for utility boilers) depending upon the boiler design. Other potential retrofit requirements include burner and windbox modifications and the addition of sootblowers and fly ash hoppers.

Depending on the original boiler design and the nature and extent of the modifications required for COM firing, it is possible and often probable that the boiler will have to be derated. The exact derating for a particular boiler can generally only be determined after an extensive study by the boiler manufacturer. Table E-1 presents a generalized guide to potential derating of oil-fired utility boilers converted to COM firing.

SCHEMATIC FLOW DIAGRAM
PULVERIZED COAL-OIL MIXTURE PREPARTION PLANT

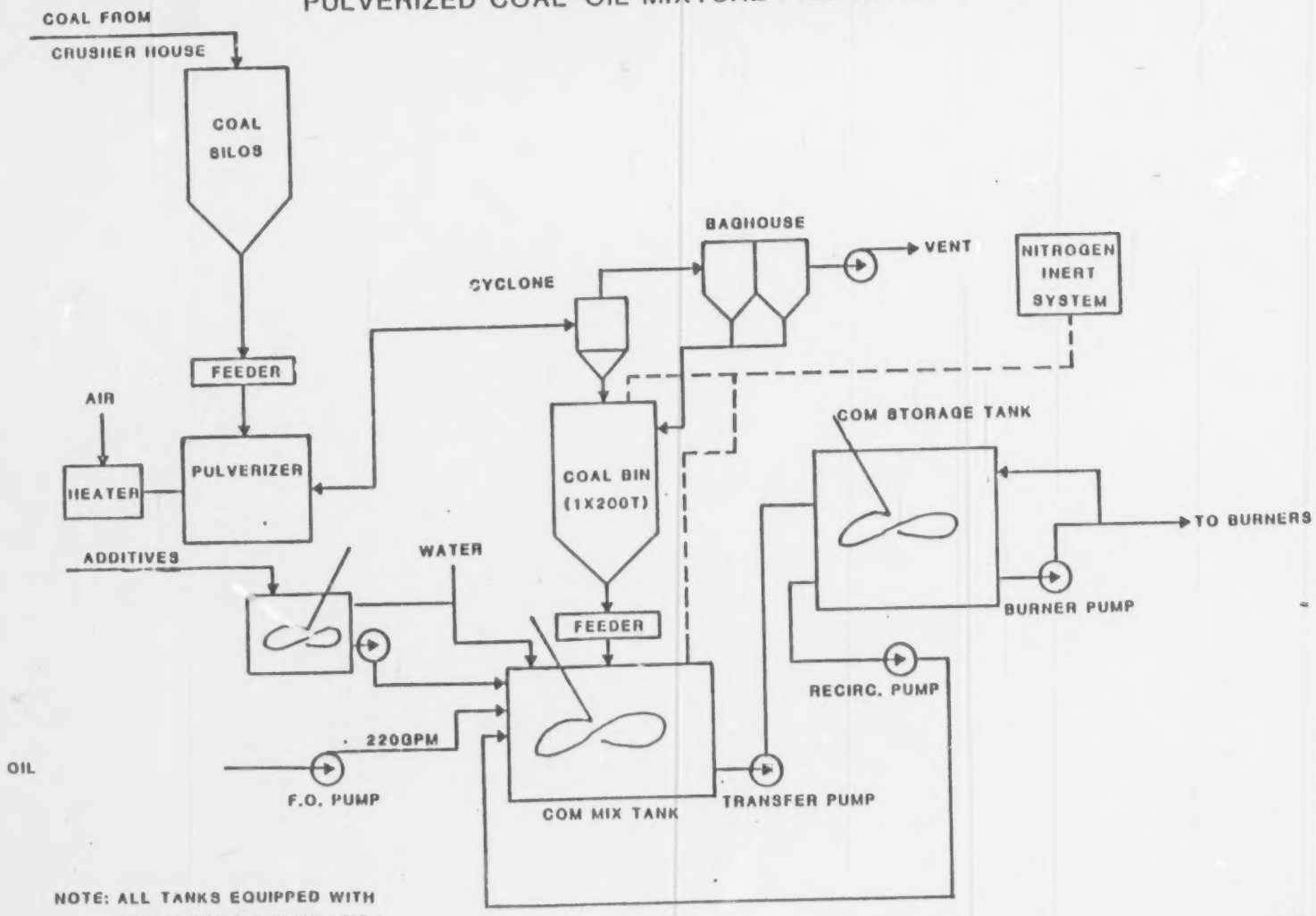

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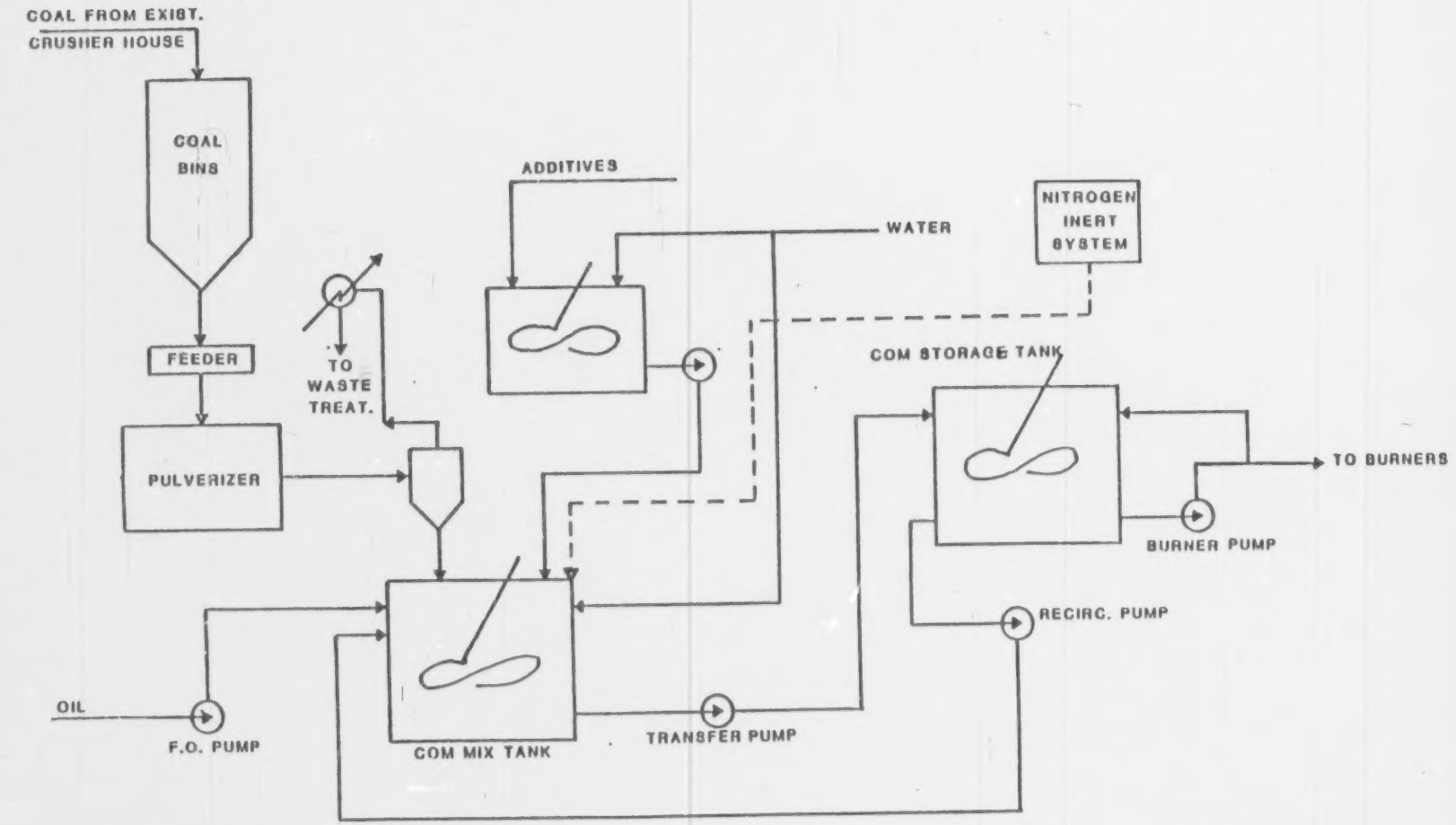
FIGURE E-1

SCHEMATIC FLOW DIAGRAM
ULTRA FINE COAL-OIL MIXTURE PREPARATION



NOTE: ALL TANKS EQUIPPED WITH STEAM COILS & INSULLATION.

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FIGURE E-2

The impact of a boiler derating on a plant's performance is related to its operating characteristics with regard to other plants of the utility system. In particular, a large derating would have a much more pronounced effect on a base loaded unit than that for an intermediate or peaking unit. Furthermore, after conversion to COM of several units of a utility, the order of "economic dispatch" may change. (Economic dispatch is the order in which units are brought "on-line" with increases in the system load.)

Some of potential drawbacks related to derating can be offset by modifying the boiler to have "dual-fuel" capabilities, i.e., modify it to burn COM but with the ability to burn oil for those periods when 100 percent output is required by the demands of the utility system.

To burn COM, other plant modifications would have to be made; in particular, new electrostatic precipitators would have to be added, or existing ones upgraded, assuming that compliance with current environmental regulations was required.

In general, careful selection of the sulfur content of coal and oil can produce a COM with an average sulfur content, expressed in pounds per million Btu of potential SO_2 emissions, that is equal to that of the fuel oil it replaces. Thus, the addition of a costly flue gas desulfurization (FGD) system can be avoided since applicable environmental regulations generally permit the substitution of a composite fuel for oil so long as appropriate emission levels are not exceeded. However, in some states (e.g., California), the appropriate emission levels are so stringent that it is doubtful if COM or CWM could be burned without FGD unless special variances are granted.

Coal-oil-water mixtures (COWM) offer an opportunity to increase the coal content of slurry mixtures to approximately 45 percent in terms of Btu's as opposed to 40 percent for COM. A typical COWM is composed of 50 percent coal, 40 percent oil, and 10 percent water, on a weight basis. In effect, a COWM fuel is a COM fuel in which 10 percent of the oil has been replaced by water. Since the coal is only pulverized to "standard grind," i.e., 80 percent passing through a 200 mesh screen, a surfactant is normally added to form an emulsion, thus inhibiting coal settling. One COWM process uses a patented ultrasonic generator to keep the coal particles in suspension. The presence of water in the COWM decreases boiler efficiency. However, experimental evidence indicates that this loss in efficiency can be offset to some extent by reduced excess air requirements because of the phenomenon known as "secondary atomization." In a COWM, particles of coal tend to agglomerate around a water droplet

nucleus due to the action of the surfactant. When the COWM is fired in the boiler, the water droplets vaporize and essentially "explode" the coal particles, thus enhancing the combustion process. The resulting flame geometry, according to experimental evidence, is quite similar to that of heavy fuel oil. Boiler and plant modifications for burning COWM are quite similar to those required for burning COM.

While coal-oil and coal-oil-water mixtures are useful for "stretching" fuel oil resources, coal-water mixtures (CWM) offer a method to entirely replace oil with coal for boilers currently burning oil. A typical schematic flow diagram is shown in Figure E-3.

Historical experience with CWM includes work performed in Germany and the USSR as well as the United States. [2] The U.S. experience is based on a 1961 test burn in a twin cyclone boiler of a 70 percent coal - 30 percent water mixture by Jersey Central Power and Light in their Werner plant in South Amboy, New Jersey.

The German and Russian work are similar to each other in that both studied 60/40 coal/water mixtures without a stabilizing agent. The results of their research is also rather similar, namely, that wet grinding technology was suitable in producing a stable mixture which exhibited good combustion characteristics.

More recent U.S. experience includes research performed by the Atlantic Research Corporation and Alfred University. The CWM developed by Alfred University has been successfully tested by Babcock & Wilcox (B&W) in the combustion test facility of their Alliance, Ohio, Research Center. This coal water mixture, called "Co-Al," consists of "71 percent eastern bituminous coal (dry basis), water and a minimum amount of chemical additives". [3] Over 12 tons of coal were burned in the Co-Al test program.

Coal-water mixtures are similar to coal-oil mixtures in that both can be prepared onsite or offsite and transported in much the same way as heavy fuel oil.

TABLE E-1

POTENTIAL DERATING OF UNITS ORIGINALLY DESIGNED FOR OIL FIRING AND CONVERTED TO COM FIRING

DESIGN CHARACTERISTICS OF ORIGINAL OIL-FIRED BOILER	POTENTIAL DERATING
Substantial Provision for Coal Firing	10-25%
Moderate Provision for Coal Firing	25-35%
Essentially No Provision for Coal Firing	35-50%

Notes:

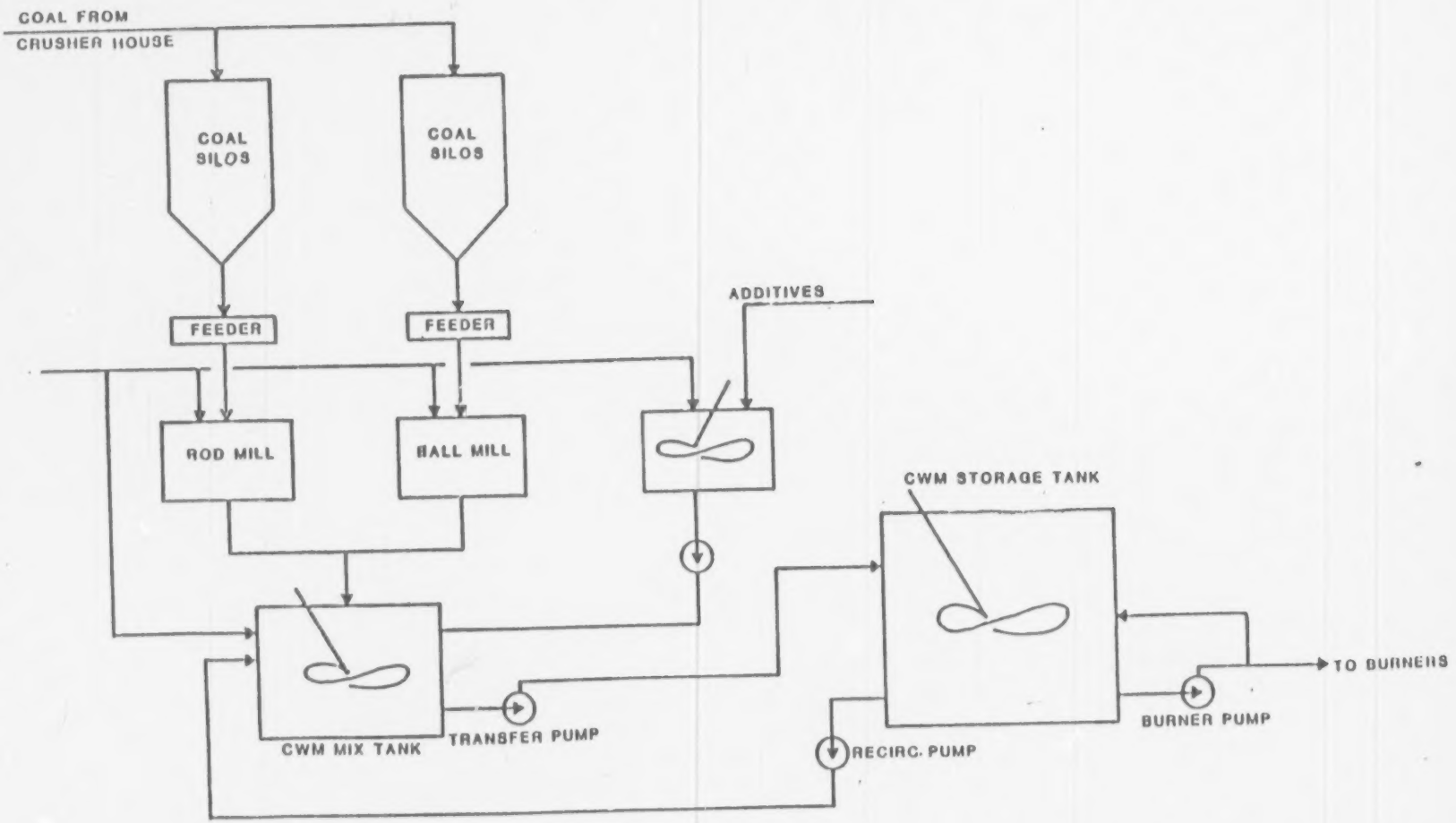
1. Boiler characteristics that can result in derating include economizer tube type (bare versus finned) and spacing as well as superheater and reheater tube spacing.

2. Boiler load regimen will also influence potential derating. In general, a base-loaded unit will suffer a greater derating than a peaking unit especially if the coal has slagging tendencies.

3. Coal and ash characteristics have a very significant influence on potential boiler derating. While it is possible to estimate their effect on potential derating, the variable nature of coal slagging and fouling properties could result in an actual derating somewhat different than initial estimates.

Source: Reference 1.

SCHEMATIC FLOW DIAGRAM
COAL-WATER MIXTURE PREPARATION PLANT



NOTE: ALL TANKS TO BE INSULATED

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FIGURE E-3

Boiler and plant modifications for CWM burning are similar in nature to those for burning COM, but they might vary in extent due to the larger amount of coal burned. In particular, boiler derating is expected to be greater for CWM burning than for COM burning. Depending on the extent, and hence cost, of the boiler modifications, B&W estimates CWM boilers may only achieve 50 to 62 percent of the original rated capacity, corresponding to 50 and 38 percent deratings, respectively.[4] This represents a potentially severe economic penalty.

It was earlier pointed out that a boiler designed to burn COM could also be modified to burn oil as an alternate fuel. However, dual-fuel firing is not yet a proven technology for CWM.

3. Commercialization Assessment

The commercialization of coal-oil mixtures compared to coal-water mixtures is relatively well advanced, including both standard grind and ultrafine processes.

To date, one utility power plant, Florida Power Corp.'s P.L. Bartow Unit No. 1, has been converted to burn COM on a permanent basis. Bartow No. 1 is a 125 MW unit originally designed to burn oil but with the capability to burn coal in the future. The COM is supplied by COMCO (a partnership of Dravo, Florida Power Corp. and the A.T. Massey Coal Co.) from a new, commercial-size COM production plant located at Port Sutton, near Tampa, Florida. The Port Sutton plant can process 15 TPH of coal and produce 3,000 barrels per day of COM. The Port Sutton facility, already committed to supply 500,000 barrels per year of COM to Florida Power Corp., is the first of a series of regional composite fuel production centers planned by COMCO.[5] The COM produced by COMCO utilizes the "ultrafine" coal approach.

The regional COM production plant concept is of potentially great value to the industrial sector for individual industries which would otherwise be unable to utilize COM because of financial considerations or lack of space for an onsite processing facility, or both. It should be emphasized, however, that COM would be of virtually no value to an industrial user if the use of COM caused the boiler to be derated to such an extent that the requirements of the industrial process could not be met.

Other valuable experience leading to commercialization of coal-oil mixtures was gained by Florida Power and Light who demonstrated in a series of tests involving their Sanford Unit No. 4 that a "standard grind" COM (using additives and

agitation) could be burned in a 400 MW unit originally designed to burn oil. Coal contents up to 50 percent by weight were demonstrated, although the boiler had to be derated. Derating was not required for coal contents up to 40 percent by weight. [6] For this demonstration, the EPA granted FP&L a variance which allowed the test to be conducted without compliance with regulations governing particulate emissions and opacity.

COM was also successfully burned in a DOE sponsored demonstration project by New England Power Service Company (NEPSCo) involving their Salem Harbor Unit No. 1 which is an 80 MW Unit originally designed to burn coal. The NEPSCo program demonstrated that coal-oil mixtures with coal contents of 20 and 30 percent could be produced and stored with virtually no settling problems by using a surfactant and occasional agitation. Valuable data concerning burners and fuel atomization were gained during the test program. Salem Harbor Unit No. 1 was able to operate at full load burning the 30 percent coal COM, but rarely did so since the normal 20 percent opacity limit was exceeded at full load and NEPSCo's variance to exceed the opacity limit was only valid for limited periods of time. An estimated $3,000,000 renovation and expansion of the precipitator could have allowed full load operation and compliance with particulate emission regulations; however, this option was not pursued by DOE. [15]

The state-of-the-art for coal-water mixtures is not as far advanced as for coal-oil mixtures. The most significant demonstration was that conducted by B&W, which was discussed earlier.

FP&L is also quite interested in this technology, but observed that several areas require further investigation before it will become commercially available: [7]

a. Determine the cost associated with a commercial CWM preparation plant

b. Determine the site specific costs for an oil-designed power plant

c. Conduct detailed combustion testing

d. Combine advanced coal cleaning with CWM technology.

While the above comments were in reference to the electric utility industry, they are generally applicable to the industrial sector as well.

Atlantic Research Corp. has an operational CWM pilot plant designed to produce 75 barrels per day of CWM for use in furnace and boiler combustion tests for various companies. [8]

The current state-of-the-art for CWM is in the pilot plant stage, with no commercial-size projects currently planned. It is expected that in 1983, more demonstration projects will be undertaken, particularly in two areas which need to be developed further:

a. Demonstrate large scale production, storage and pumping facilities.

b. Develop more reliable burners.

If such demonstration projects were to be successful, and a commitment was made to demonstrate CWM on a commercial scale in early or mid-1984, then it is quite possible that CWM could be commercially available by late 1985.

One manufacturer of a COWM (although the manufacturer calls it simply a COM) claims to have "produced, transported (via commercial carrier over 900 miles) and burned commercial quantities" of their COWM. [9] One hundred and fifty thousand gallons of this particular COWM was successfully tested in a 65,000 lb/hr boiler.

4. Oil Replacement Potential

Due to the similarities of COM and CWM technologies, and to the comparable nature of the constraints to use of each fuel, it is assumed that the market potential is the same for each fuel. In other words, it is assumed that if a boiler is considered to be a candidate for COM, then it is an equally attractive candidate for CWM, and vice versa. Similarly, if a boiler is not a potential candidate for one mixtures then the other is excluded as well. Although the market potential is assumed to be the same, this does not imply that the oil replacement potential is the same. On the contrary, if it is assumed that there will be no differential boiler derating using either of the two fuels, then the oil replacement potential for COM is approximately 40 percent of that for CWM. This merely reflects the fact that a typical COM envisioned would supply only 40 percent of the required Btu's with coal whereas for CWM the oil replacement would be 100 percent. Regarding the assumption that the boiler derating, if any, would be the same for each fuel, it should be noted that the boilers most amenable to conversion would generally include a large fraction of units for which derating would be small or nonexistent. Substantial derating

is one of several factors that would tend to disqualify a boiler for conversion to COM or CWM.

Table E-2 illustrates a recent DOE estimate of coal-water mixture market potential.[11] The anticipated market penetrations for the utility industrial and commercial sectors are based on a consideration of the major constraints to implementation such as boiler derating, space availability, and air emissions regulations.

The DOE estimate is for industrial/commercial boilers larger than 100 MMBtu/hr rated capacity and market penetration for boilers in the 50-100 MMBtu/hr capacity needs to be added. There are about 2500 distillate and residual oil fired water tube units in this size range in the country with an installed capacity of about 185 x 10^9 Btu/hr. Assuming a 25 percent market penetration and 30 percent capacity factor, these boilers represent an oil displacement potential of 60,500 boe/d (= 185 x 10^9 x 0.25 x 0.30 x 24/5.5 x 10^6).

Boilers smaller than than 50 MMBtu/hr are excluded from consideration because of potentially large derating and diseconomies of scale resulting from the application of particulate collection devices for these smaller boilers.

Table E-3 presents the daily and annual oil displacements for CWM and COM for the utility, industrial, and commercial sectors. It is assumed that COM only displaces 40 percent of the oil displaced by CWM. Annual oil displacements are calculated using the DOE estimates of capacity factors from Table E-2 for utility and plus 100 MMBtu/hr boilers and 30 percent for 50-100 MMBtu/hr range boilers.

5. Costs

Before discussing cost estimates for conversion to COM or CWM, a few comments about cost estimates of this type are in order since costs for COM/CWM conversion can only be realistically assessed if a variety of technical and economic parameters are clearly defined.

Perhaps the single most important fact to ascertain first is whether the design in question includes an onsite composite fuel facility or if the COM/CWM is purchased from an offsite facility. In the former case, part of the COM/CWM cost is included in the capital cost, whereas in the latter case the COM/CWM cost is entirely part of the fuel cost.

It is also quite important in economic calculations to indicate the plant derating in order to estimate the value of lost capacity and generation that results from derating.

This is a potentially significant cost item and should be clearly identified in economic comparisons.

Economic comparisons may either be presented on a "first-year" cost basis or a "levelized" cost basis. Levelized costs for COM/CWM are a function of, in addition to the first costs, the escalation rates for oil and coal and the discount rate.

The Electric Power Research Institute (EPRI) sponsored a major study of coal-oil mixtures as a utility fuel.[12] The study examined technical and economic considerations for the conversion of 4 units, designated Plants No. 1, 2, 3 and 4, to COM which was assumed to be prepared offsite. The costs for COM and plant modifications as well as plant capacities and deratings from this study are shown in Figure E-4. The COM cost varies due to differing sulfur contents and specific transportation costs. The cost of plant modifications in dollars per derated kW was not shown explicitly in Reference 12; it was derived by dividing the total investment cost by the derated kW output. The total investment costs includes COM receiving, storage, and handling systems, boiler modifications, ash handling systems, and where required, replacement of, or modification to the electrostatic precipitators. The total investment cost also includes indirect costs, engineering and contingency. It does not include startup costs.

Plant derating was obtained from the formula:

$$\text{Percent Plant Derating} = \left[\frac{1 - \text{kWe burning COM}}{\text{kWe burning oil}}\right] \times 100$$

It should be noted that the plant derating consists of the boiler derating and the effect of reduced turbine-generator efficiency due to the reduced load. However, the boiler derating has a considerably greater effect than the reduced turbine-generator efficiency.

Table E-4 does not conclusively demonstrate a relationship between cost of plant modifications and plant derating. However, the relative high cost for Plant No. 4 is certainly greatly affected by the exceptionally high derating. In fact, it is reasonable to assume that Plant No. 4 is not in the top 50 percent of oil-fired plants that are most amenable to COM conversion. Consequently, only Plants 1, 2 and 3 are used to develop the "average" cost shown in Table E-4.

TABLE E-2

COAL WATER MIXTURE MARKET POTENTIAL

(UTILITY BOILERS 50 MW MIN., INDUSTRIAL BOILERS 100 MILLION BTU/HR MIN., COMMERCIAL BOILERS 100 MILLION BTU/HR MIN.)

USE	TYPE OF INSTALLATION	NO. OF UNITS	CAPACITY MW	PENETRATION %	OIL DISPLACED BBL/DAY
UTILITY	DESIGNED FOR COAL	220	30,165	50	149.0×10^3
UTILITY	DESIGNED FOR OIL	245	63,279	50	313.0×10^3
				SUBTOTAL	462.0×10^3
INDUSTRIAL (SATURATED STEAM)	DESIGNED FOR COAL CURRENTLY BURNING OIL/GAS	350	10,479	50	72.5×10^3
	DESIGNED FOR OIL	1,065	12,419	25	43.0×10^3
INDUSTRIAL (SUPERHEATED STEAM)	DESIGNED FOR COAL CURRENTLY BURNING OIL/GAS	75	5,821	50	40.0×10^3
	DESIGNED FOR OIL	226	6,900	25	24.0×10^3
COMMERCIAL	DESIGNED FOR OIL	243	4,683	25	11.0×10^3
				SUBTOTAL	190.5×10^3
				TOTAL	652.5×10^3 BBL/DAY
				COAL REQUIRED	60.0×10^3 TON/YR

ASSUMED YEARLY CAPACITY FACTORS - UTILITY 0.25
INDUSTRIAL 0.35
COMMERCIAL 0.24

Adapted from Ref. 11

TABLE E-3

OIL DISPLACED BY CWM AND COM

SECTOR	OIL DISPLACED(*) (BARRELS/DAY)		OIL DISPLACED(*) (MILLION BARRELS/YEAR)	
	CWM	COM	CWM	COM
Utility	462,000	185,000	168.7	67.6
Industrial	179,500	71,800	65.5	26.2
Commercial	11,000	4,400	4.0	1.6
Medium Industrial(**)	60,500	24,200	22.1	8.8
Total	713,000	285,400	260.3	104.2

(*) Does not include derating
(**) 50-100 MMBtu/hr residual and distillate oil-fired boilers.

After eliminating Plant No. 4 from the data base of plants potentially amenable to COM conversion, the cost data appears to be more consistent. It should be noted that Plant No. 2 includes the cost of a new electrostatic precipitator whereas Plants No. 1 and 3 do not. This partially explains why Plant No. 2 has a higher modification cost in dollars per derated kWe than Plant No. 1, even though Unit 2 has a lower derating. The average of the three plant modification costs is approximately 75 dollars per derated kWe, where the average derating is about 29 percent. Because of the small data base and the site-specific costs that would affect other plants, a range of 75 to 100 dollars per derated kWe is used to provide a conservative "rule-of-thumb" or "ballpark" estimate for plant modification costs.

Reference 13 indicated that in 1980, the oil-fired utility generation of potential interest to COM conversion amounted to 93,444 MW of capacity, of which 30,165 MW were units designed for coal and 62,279 MW were units designed for oil.

Assuming this estimate is equally valid for 1982, and using the DOE estimate discussed earlier that 50 percent of the capacity of units designed for coal or oil might be converted to COM, then approximately 46,700 MW of capacity would be acceptable for conversion. Using our estimate of 75 to 100 dollars per derated kWe, the conversion of 46,700 MW of nameplate oil-fired capacity would cost approximately 2.5 to 3.3 billion dollars in 1982. Furthermore, assuming an average 29 percent derating, this capacity would be reduced to 33,200 MW.

Although the costs for CWM preparation plants and power plant modifications are not as well known as for COM, it is assumed for the purpose of this study that they are comparable and can be represented by the same gross capital investment. Table E-5 illustrates the 1982 capital costs for COM/CWM for both the utility and industrial/commercial sectors expressed in dollars per barrel per day of oil displaced. Note that the fuel preparation plant costs are shown separately. Costs were developed using data from Reference 14 and Gibbs & Hill in-house cost estimates. The oil displacement data was taken from Table E-3.

The capital costs for plant modifications to facilitate combustion of coal mixtures do not include flue gas desulfurization (FGD) systems. Conversions of oil-fired units to coal mixture-firing have utilized low sulfur coals, as well as low ash coals, to eliminate the need for FGD. If a situation were to arise where FGD were required by local regulation, the attraction of conversion to coal mixtures would be severely reduced. First, FGD systems for large plants can add 150 to 200 $/kWe, which would increase dramatically because of diseconomies of scale for small plants. Secondly, space availability would become a problem for many utility and industrial sites. Under these circumstances it is assumed that coal mixture conversion would not be undertaken.

The "first-year" costs for COM and CWM are shown on Table E-6 in terms of dollars per equivalent barrel of oil for the utility and industrial/commercial sectors. The capital costs include only plant modifications shown in Table E-5. The coal is purchased at the required quality, i.e., ash and sulfur levels and has fusion temperature consistent with operability and environmental requirements. The COM fuel cost, which includes capital charges for the COM preparation plants, is from Reference 12. For comparison purposes the CWM cost is derived from Reference 12 data and is consistent with current estimates of CWM cost.[16] The O&M costs were adapted from Reference 13. For this study, it was assumed that O&M costs were the same for COM as for CWM.

TABLE E-4

EPRI COM STUDY DATA

PLANT NO.	CAPACITY NAMEPLATE/ DERATED (MWe)	DELIVERED COM COST ($/10^6 Btu)	COST OF PLANT MODIFICATIONS ($10^6 $)	COST OF PLANT MODIFICATIONS ($/derated kWe)	PLANT DERATING (%)
1	850/599	3.81	20.0	56.6	29.5
2	820/666	3.54	32.8	80.2	19.5
3	565/362	4.01	17.0	88.0	37.7
4	410/186	3.82	20.9	197.8	56.4
AV*	745/542	3.79	23.3	74.9	28.9

*The Average of Plants No. 1, 2 and 3.

TABLE E-5

CAPITAL COST OF COM/CWM FACILITIES
AND PLANT MODIFICATIONS
(1982 $/bbl/day)

COAL OIL MIXTURE(*)

	Utility	Industrial/Commercial(***)
Plant Modifications	19,300 to 25,500	29,500 to 46,500
Processing Facilities	3,900	3,900
Total	23,200 to 29,400	33,400 to 50,400

COAL WATER MIXTURE(**)

	Utility	Industrial/Commercial(***)
Plant Modifications	9,800 to 13,800	11,800 to 18,800
Processing Facilities	2,000	2,000
Total	11,800 to 15,800	13,800 to 20,800

(*) Assumes 30 percent derating
(**) Assumes 45 percent derating
(***) Includes new CWM-fired boilers to replace capacity lost by derating

TABLE E-6

FIRST YEAR COSTS FOR COM AND CWM OPTIONS
(1982 $/bbl oil equivalent)

	UTILITY		INDUSTRIAL/COMMERCIAL	
	COM	CWM	COM	CWM
Capital Charges(*) (Plant Modifications Only)	10.6 to 14.0	5.4 to 7.6	16.2 to 25.5	6.5 to 10.3
Fuel(**)	21.9	18.2	20.9	17.3
O&M	1.9	1.9	2.7	2.7
Total	34.4 to 37.8	25.5 to 27.7	39.8 to 49.1	26.5 to 30.3

(*) From Table E-5
(**) Assumes oil-fired utility and industrial boilers have 86 and 82 percent efficiency, respectively, and COM and CWM boilers have 82 and 70 percent efficiency, respectively, for both sectors.

Economic comparisons are sometimes performed on a "payback" method. Reference 14 includes a "payback" type economic comparison of four options available to an industrial user who has six 44 MW oil-fired boilers operating at 54 percent load factor. The results are presented below:

Option	Capital Cost (10^6 $)	Payback Years
Stay with Oil	0	-
Convert to Arc-Coal*	7-11	1.2-2
Convert to Pulverized Coal	55	7.2
Convert to Spreader-Stoker Coal	60	8.4

*Arc-Coal is a proprietary CWM

The above economic comparison was based on the following assumptions:

a. Residual Oil = $32/bbl delivered

b. Steam Coal (0.7%S, 5% ash) = $46/ton delivered

c. Arc-Coal = $14/bbl delivered

d. 59 MW Pulverized Coal Boiler = $14,000,000

e. 44 MW Stoker Coal Boiler = $10,000,000

f. Annual Interest = 15%

6. Non-institutional Constraints

Some of the potential non-institutional constraints have been touched upon in earlier discussion of COM and CWM technologies. Generally speaking, the boiler is the single most important technical factor that could discourage conversion to composite fuels. Some boilers cannot be converted to COM or CWM without extensive and costly modifications or significant deratings or both. Other boilers may be so old that there is no economic justification for modifying it since the remaining useful life may be less than the economic life of the capital improvements. Also, it was previously indicated that excessive derating of an industrial boiler could prevent it from meeting steam demands essential to the process it serves.

Lack of space at utility or industrial plant sites could preclude onsite production of COM/CWM. This would tend to make offsite production of COM/CWM more attractive. Also, solid wastes such as fly ash, bottom ash and slag would have to be disposed of in an environmentally acceptable manner. Lack of a suitable disposal site, either onsite or offsite could be a serious impediment to conversion to COM/CWM.

While COM and CWM can be transported, in theory, to any part of the United States, there are two important considerations if the transportation distance is substantial:

a. The transportation cost could be prohibitive

b. Other than COM employing ultrafine coal, settling out could present a serious problem during the unloading process.

The settling out problem might be overcome, or at least lessened, with improvements in chemical agents to inhibit settling.

Coal quality is another important consideration in COM and CWM processes. For COM, where only 50 percent of the mixture (by weight) is coal, acceptable coal ash contents are typically 10 percent, giving the COM an ash content of about 5 percent. Coals with this ash content, as well as the requisite sulfur content, can generally be obtained in sufficient quantity from existing coal supply sources. These coals may either be high quality raw coals or beneficiated coals. However, since coal represents 100 percent of the weight of CWM, it is generally desirable to employ coals with a maximum ash content of approximately 5 percent, particularly in boilers designed only for oil firing. Such coals are not readily available, either raw or beneficiated. Current beneficiation technology could produce such coals using "deep cleaning," but at a significant cost premium. Since deep cleaning also produces an intermediate quality coal, called "middlings," it is essential that the middlings be readily marketable, otherwise this process could not be economically justified. Boilers originally designed for coal might be able to successfully burn CWM with an ash content in excess of 5 percent, but they would have to be evaluated on a case-by-case basis.

As outlined in Section IV.B, the constraint imposed by strategic materials on implementation of CWM and COM technologies is rated 'medium' based on use of these materials for CWM and COM.

7. Institutional Constraints

The single most important institutional constraint with regard to the use of coal-oil and coal-water mixtures concerns federal, state, and in some instances, local air emission regulations.

Federal regulations protecting the air environment include:

a. New Source Performance Standards (NSPS)

b. National Ambient Air Quality Standards (NAAQS)

c. Prevention of Significant Deterioration (PSD)

d. New Source Review (NSR).

The current NSPS regulations, effective July 11, 1979, explicitly exempted conversion to coal-oil and coal-oil-water

mixtures on the grounds that such conversions do not represent major modifications. The same exemption also applies implicitly to coal-water mixtures since it is in the category of "any other coal derived fuel."*

Units converted to burn COM or CWM may be required to comply with NAAQS, PSD and NSR requirements.

NAAQS defines an area as attainment (below standards) or non-attainment (above standards). In general, emissions from a converted facility should not exceed NAAQS.

The PSD requirement may be waived if conversion to COM or CWM does not result in a significant net increase in air emissions, and in particular, that emissions from the converted facility does not exceed the emissions before conversion plus an EPA allowance known as the "de minimis" level. Applicants for a PSD waiver must request EPA approval, in writing, including information necessary for the EPA to duplicate the emission analyses. Such a request can then replace the federal NSR requirement.

Units converting to COM or CWM will also have to satisfy appropriate state air quality regulations and standards before a permit can be granted for the modification. Although these regulations and standards normally vary from state to state, in general, all states regulate emissions of sulfur oxides (SOx), oxides of nitrogen (NOx), and total suspended particulates (TSP).

In some instances, there are local air emission regulations more stringent than those of the state. This is particularly true in certain large urban areas.

Solid wastes generated by burning COM or CWM, including fly ash, bottom ash, and slag are considered conventional and not hazardous wastes, thus, federal hazardous waste regulations do not apply. However, state solid waste laws may apply, including appropriate permits.

A potentially significant institutional constraint to conversion to COM or CWM (or similar modifications) for an electric utility regards how the capital cost of modifications is recovered by the utility. The traditional method of recovering capital costs through an increase in the rate base after the conversion is complete may act as a disincentive to a utility in an unfavorable economic environment of high interest rates and other related factors. Some states allow "construction work in progress" (CWIP) to

*Federal Register, Vol. 44, No. 113, pp. 33588-89.

be passed along to the ratepayers (although to different extents). This would encourage utilities to expend capital resources since it could be recovered sooner. Finally, "innovative" fuel adjustment clauses have been proposed by utilities as an alternate means to encourage conversion of oil burning facilities to technologies which employ coal. This innovative fuel adjustment clause would, in effect, have the cost of modifications (in whole or in part) passed along to the ratepayers such that the "pass-along" costs are less than or equal to the difference in fuel adjustment charges for burning coal (or a composite fuel) as opposed to burning oil.

Any design features which may decrease plant reliability, such as FEO systems, are resisted by utilities because of their adverse effect on utility earnings (see Section D.7)

8. References

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(2) Marnell, Paul. "Direct Firing of Coal-Water Suspensions - State of the Art Review," presented at Coal Technology '80, Houston, TX, November 18-20, 1980.

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(14) Henderson, Charles B. "Coal-Water Fuel Development," Proceedings of the Coal-Water Fuel Technology Workshop, March 18-21, 1981, BNL-51427, 1981.

(15) Dunn, R.N., and S.K. Batra. "Result of the Salem Harbor Coal-Mixture Demonstration," Third International Symposium on Coal-Oil Mixture Combustion, CONF-810498 (Vol. 1) 1981.

(16) "Atlantic Research CWM Pilot Plant Opens For Business," Coal R&D, February 2, 1983.

F. COAL GASIFICATION

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F-1 Coal Gasification Plant - Block Flow Diagram

1. Introduction

Coal gasification has the potential to replace some oil within the 5 years of an oil supply disruption. Its primary contribution would be to displace oil in large utility and industrial boilers. Numerous processes exist to produce fuel gas from coal. However, many of these processes have not yet been sufficiently developed to be considered commercially available. A few have operated commercially and some others are expected to be sufficiently developed by 1985 to be considered commercially available.

2. Description

Fuel gases produced by the various gasification processes have a wide range of heat capacities. These are catagorized as low, medium and high Btu fuel gases. The production of low and medium Btu gases is generally less costly and results in a better thermal efficiency. This discussion will deal with displacing oil with low or medium Btu gas.

Low Btu fuel gas generally has a heat content of 90-170 Btu/SCF and medium Btu gas falls in the 250-350 Btu/SCF range. Both are composed of carbon monoxide (CO), hydrogen (H_2), carbon dioxide (CO_2), nitrogen (N_2), methane (CH_4) and in some cases, various other hydrocarbons, along with impurities which may have to be removed prior to using the gas. This is particularly true of sulfur compounds, ammonia and particulates. Some processes produce significant amounts of tars or oils which can be recovered as a by-product.

Gasifiers exist which can convert virtually any coal (or peat) to fuel gas. However, each process has some limitations with respect to the properties of the feedstock it can successfully gasify. Feed properties are more restrictive for some gasifiers than for others. Coal properties which are often important are ash fusion temperature, moisture content, caking properties and coal type. The size consistency of the feed is also important for most gasifiers. Prior to selecting a particular gasifier, the gasifier's feed requirements should be compared to the properties of the coal which is intended as the feedstock. Various gasifiers operate from atomospheric pressure to over 1000 psig.

Figure F-1 shows a generalized block flow diagram for a coal gasification plant.

Raw coal is received in Area 1, Coal Handling and Storage. This area will contain the equipment to receive coal, transfer it to Area 2, Coal Preparation. The coal storage is generally divided into two piles. One pile, live storage, is

continually being reclaimed and replenished and typically will hold about 5 days worth of coal. The other pile, dead storage, is built up prior to starting the gasification plant. This pile, which is sealed and compacted, is used only during interruptions to the normal coal supply. Coal shipments will usually be delivered by rail or barge if the plant is far from the mine(s). If the plant is near the mine, truck or conveyor delivery is used.

In the Coal Preparation Area (Area 2) coal is treated, as required, to make it suitable for the particular type of gasifier used in the plant. The operations typically found in this area are size reduction (crushing/grinding), screening or some other method of size classification, drying, coal pressurization and controlled-rate feeding to the gasifier. Depending on the size consistency and moisture content of the coal coupled with the gasifier's requirements and operating conditions, some of the above treatments may be eliminated.

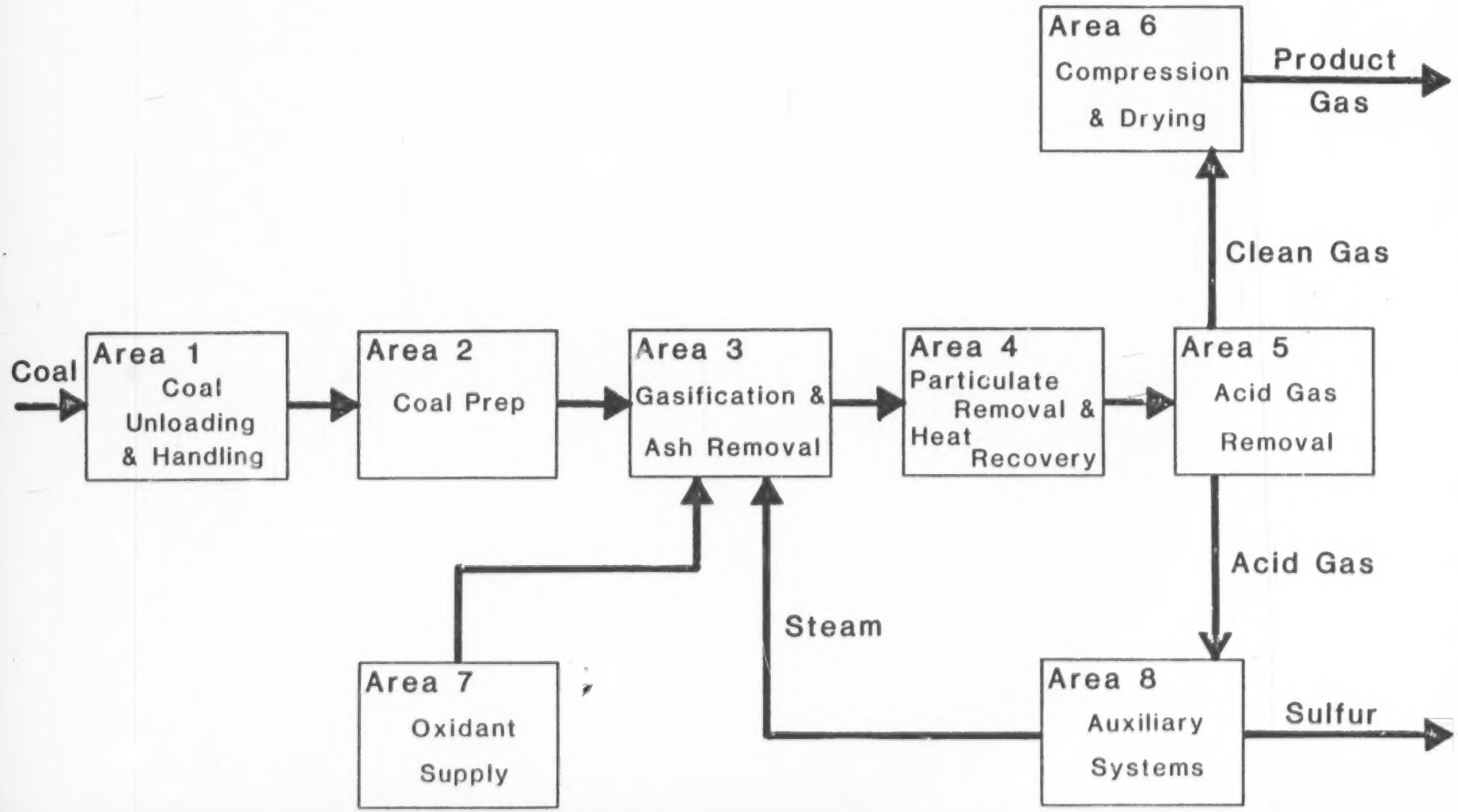
In Area 3, Gasification, coal is reacted with steam and an oxidant to produce a raw, hot gas. Some gasification processes produce more than enough steam to meet the gasifier's demand and may generate enough excess steam to produce some electricity. The oxidant is air or oxygen. The gasifier is usually one of three types, fixed bed, fluid bed or entrained bed. Some other types (e.g., molten salt) are used but these are not expected to have operated at or near commercial scale by 1985 and will not be considered here. This area also include the necessary bins, hoppers and conveying equipment to remove and dispose of the ash.

The hot raw gas contains various amounts of CO, CO_2, H_2, N_2, water vapor and sulfur compounds (mostly H_2S). It may also contain CH_4, illuminants (C_2's & C_3's), ammonia, tars/oils and particulate matter (ash and unreacted coal).

If environmental restraints are sufficiently lessened due to the nature of the circumstances surrounding the oil supply disruption and if the gas user can accept the gas as is, the gas can be burned in the hot, raw state and will result in the lowest cost gas and greatest thermal efficiency. If tars/oils are present, the gasifier would have to be physically located very close to the user and means to prevent tar/oil condensation would have to be provided.

Figure F-1

Coal Gasification Plant–Block Flow Diagram



However, it is probable that some clean-up will be required to meet environmental and/or operational constraints. Therefore, the next step in the treatment of the gas would be to remove particulates, recover heat and to remove any tars and oils in the gas. This is accomplished in Area 4, Heat Recovery and Particulate Removal. Process equipment used in this area may include cyclones, heat exchangers, electrostatic precipitators, scrubbers and decanters. If any ammonia is present in the raw gas, it will be removed in the scrubber. The gas is now cool and free of particulates, tar/oils and ammonia.

The gas then passes to Area 5, Acid Gas Removal. Here the gas is scrubbed with a chemical solution to remove H_2S and, in some cases, other sulfur compounds. The sulfur bearing gases are separated from the solution and treated to recover sulfur as a by-product.

The gas may then need to be dehydrated and compressed in Area 6, Dehydration and Compression. Since the gas is normally near saturation at this point, some water vapor has to be removed to prevent condensation and perhaps freezing in the pipeline and control equipment. This is done either with beds of solid desiccants or contact with a glycol. The gas, at this point can be at a fairly high pressure (several hundred psig) or near atmospheric. The gas must have sufficient pressure to overcome line and control valve losses and have sufficient pressure for proper burner operation at the user. If insufficient pressure is available, the gas is compressed. Compression can be accomplished before or after dehydration.

Area 7, Oxidant Supply, is used to provide air or oxygen to the gasifier. If a low Btu gas is suitable for the intended gas use, this area will consist only of blowers or compressors to move the required quantities of air to the air blown gasifier at gasifier operating pressure. If a medium Btu gas is required, oxygen (usually about 98 percent) is used to avoid diluting the combustable components with atmospheric nitrogen. It is basically this dilution by N_2 that determines if low or medium Btu gas is produced. If oxygen is used as the oxidant (oxygen blown gasifier) this area will consist of an air separation plant. In an air separation plant air is compressed, cooled and liquified by expansion using the Joule-Thompson effect. It is then distilled cryogenically at near atmospheric pressure to produce nearly pure oxygen. The product oxygen is then compressed sufficiently to move it through the pipes and into the gasifier.

Areas 1 through 7 include those operations necessary to produce the fuel gas in a usable form. There are a number of other operations necessary to provide all the utilities and

waste treatment facilities necessary to gasify coal in an environmentally acceptable manner on a grass-roots basis. These are shown in Figure F-1 as Area 8, Auxiliary Systems. The systems included in this area are briefly described next. Water treatment provides water for boiler feed water make-up, cooling water, potable water, and process water. Cooling tower provides a steady supply of circulating cooling water for use in plant heat exchangers. Instrument air system provides clean, compressed air to operate instruments and controls. Sulfur recovery system provides the equipment to process acid gas from Area 5 and recover elemental sulfur or sulfuric acid. Ammonia recovery may also be provided to recover anhydrous ammonia with some gasification systems. Wastewater treatment system processes wastes and blowdowns to make the aquious wastes suitable for recycle or discharge. An auxiliary boiler is provided to balance steam demand and for use on start-up. A flare is included to provide safe method for disposal of fuel gas when it is unsuitable for its intended end-use such as during start-up or during process upsets. A thermal oxidizer may be provided to destroy low Btu combustable waste streams. A landfill may provided to dispose of ash and sludges. This may be on-site or off-site. An electrical substation is also required to serve the gasification plant.

Some of the services and utilities provided in auxiliary systems may be available in the facility which is to be served by the gasification plant. Therefore, the need for the systems normally found under auxiliary systems must be determined on a case-by-case basis. In most cases, the majority of these items will have to be supplied, or at least supplemented, within the gasification facility.

The use of fuel gas to displace fuel oil does have considerable potential. However, some boiler retrofit may be required and some degree of derating may result when fuel gas is used in place of oil. The retrofit requirements and degree of derating must be determined on a case-by-case basis. The use of fuel gas will result in new combustion air requirements, flue gas volumes and flame temperatures. These factors must be carefully considered in conjunction with boiler design when a boiler is a candidate for retrofit.

Both flue gas and fuel gas volumes (per MMBtu) are higher for low Btu fuel gas than for medium Btu fuel gas as seen in Table F-1. Flue gas volume for natural gas is between the two fuel gases. When compared to oil (on a per Btu basis), the low Btu fuel gas has a somewhat lower combustion air requirement, but will have a somewhat higher flue gas volume. The medium Btu gas has lower air requirements and similar flue gas volumes. The difference will probably be slight and will depend on the analyses of fuel gas and oil. These

factors should be determined experimentally or in consolidation with a boiler manufacturer.

If a boiler is to be converted from oil to fuel gas some changes will have to be made. As a minimum new burners will be needed and new piping will have to be installed to get the fuel gas to the boiler. If it is a dual fired unit (oil/natural gas), the existing gas piping might be used if the fuel gas is supplied at higher pressure. Additional, possible modifications include new or larger windboxes, piping and gas controls, additional or modified safety and combustion controls, new or larger draft fans, modification of flue gas duct work and some rework of the heat exchange sections of the boiler.

The major considerations in retrofit are cost, boiler capacity and efficiency. Tables F-2 and F-3 indicate the changes in efficiency and capacity, respectively, that might be expected during a retrofit.

One advantage in converting an oil fired boiler to fuel gas, as opposed to coal or a coal containing mixture, is that the gas contains no ash. Boiler modifications required to convert a boiler to coal, if it was originally designed only for oil, are likely to be much more costly and difficult.

Tables F-2 and F-3 clearly show the performance advantages to the use of a medium Btu fuel gas. Its disadvantages are cost, and a somewhat lower overall thermal efficiency of the gasification process due to the high power requirements for an air separation plant. Medium Btu gas is also less costly to transport due to the small volumes for a given heat load.

TABLE F-1

FLUE GAS PRODUCT COMPARISON

FROM PERFECT COMBUSTION

	Formula	Cubic Feet per Cubic Feet of Combustibles				Cu. Ft. of air per MMBtu	Cu. Ft. Fuel per MMBtu	Cu. Ft. of Flue Gas per MMBtu
		COd	HdO	Nd	Total			
Carbon Monoxide	CO	1.0	---	1.882	2.882	7,420	3115	8,977
Hydrogen	H2	---	1.0	1.882	2.882	8,660	3635	10,476
Methane	CH4	1.0	2.0	7.528	10.528	10,452	1097	11,550
Propane	C3H8	3.0	4.0	18.821	25.821	10,243	430	11,100
Distillate Fuel Oil	---	---	---	---	---	9,667	---	9,365

TABLE F-2

TYPICAL BOILER EFFICIENCY RERATES

FUEL	ORIGINAL DESIGN FUEL		
	COAL	OIL	GAS
Original Fuel	90%	90%	85%
300 Btu/scf HHV(*)	86% (-4%)	87% (-3%)	86% (+1%)
150 Btu/scf HHV(*)	81% (-9%)	81% (-9%)	79% (-6%)

(*) Higher heating value
Source: Ref. (1)

TABLE F-3

TYPICAL BOILER CAPACITY DERATES

WITH MINOR MODIFICATIONS

FUEL GAS HHV(*)	% OF RATING WITH OIL
290	100
180	70
130	65
105	50

WITH MAJOR MODIFICATIONS

290	100
180	100
130	100
105	60

(*) Higher Heating Value, Btu/scf
Source: Ref. (2)

3. Commercialization Assessment

There are some gasifiers which are now available as commercial equipment. In addition at least two additional gasifier types should be available by 1985. A few small gasifiers are in operation in the United States today. In the 1920's, a large number (over 11,000) were in operation but these were replaced when plentiful, cheap supplies of natural gas and petroleum became available.

A number of older, fixed bed units have been operated in the past and are available now. These include the Lurgi, Wellman-Galusha, Wilputte, Riley-Morgan and Woodall-Duckham Gasifiers. These may all be either air or oxygen blown and, except for the Lurgi, all are primarily designed to operate at atmospheric pressure.

The Koppers-Totzek gasifier is an entrained bed which is oxygen blown and operates at one atmosphere although the newer versions can operate at elevated pressures. The Babcock & Wilcox gasifier is an entrained bed, atmospheric or pressurized gasifier which may be air or oxygen blown.

Gasifiers which may not yet be considered as commercially available are the Texaco and Westinghouse gasifiers. These are expected to be considered commercially available by 1985 and could possibly be considered in that category now. Both of these can be air or oxygen blown to produce a low or medium Btu gas.

The major problem in commercialization is not the availability of coal gaification technology. It is the time lag from when an order is placed to when the plant goes on stream. For small gasifiers (50 to 100 MMBtu/hr capacity) based on package type gasifier modules (e.g., Wellman Galusha), the time lag would be about 2 years if normal design, procurement and construction procedures were followed. For the larger units such as Westinghouse, Koppers Totzek, Babcock & Wilcox, and Texaco this time would probably be on the order of three to four years.

4. Oil Displacement Potential

During imported oil cut-off, accelerated changeover to coal derived gas during a five year period is feasible mainly for oil-fired industrial and commercial boilers, each rated at or above 25 MMBtu/hr capacity. The rationale for excluding oil-fired electric utility boilers and less than 25 MMBtu/hr capacity boilers is as follows:

a. Large gasifiers which are economically more feasible for electric utility applications require three to four

years lead time, thus precluding a major penetration of the potential market.

b. Conversion/reconversion of electric utility boilers to pulverized coal firing or coal-water mixture firing is generally more cost effective than firing of coal-derived gas (see Appendices D and E for these former options).

c. There are about 120,000 distillate and residual oil-fired fire-tube boilers in the U.S. in the 0.4 to 25 MMBtu/hr capacity range with a total installed capacity of about 420 x 10^9 Btu/hr[7]. The corresponding population of water-tube boilers comprises about 13,700 units with a total installed capacity of about 87 x 10^9 Btu/hr[7]. At an average capacity factor of 0.30, the oil replacement potential for these boilers at 25 percent penetration is in the 166,000 bbl/d range (=507 x 10^9 x 0.30 x 24 x 0.25/5.5 x 10^6). However, given the dispersed population and diseconomies of scale when converting small boilers to solid fuel firing, these boilers are better candidates for conversion to natural gas.

For the medium to large (over 25 MMBtu/hr each) industrial and commercial boilers, coal derived gas is a feasible option. The oil displacement potential represented by these boilers is estimated to be 340,000 bbl/d as follows:

a. For the industrial and commercial boilers in the plus 100 MMBtu/hr capacity range, the oil replacement potential is estimated to be 190,500 bbl/d (see Table E-2 of Appendix E for coal-liquid mixtures).

b. There are about 1,400 individual oil and distillate oil fired fire-tube boilers in the 25-50 MMBtu/hr capacity range with a total installed capacity of 52 x 10^9 Btu/hr. (There are no reported fire-tube boilers in the plus 50 MMBtu/hr capacity range.) The corresponding data for water-tube boilers in the 25-100 MMBtu/hr capacity range is about 8,400 units with a total installed capacity of about 400 x 10^9 Btu/hr. Assuming a 30 percent capacity factor for these boilers and a 25 percent market penetration, these fire-tube and water-tube boilers represent an oil displacement potential of 148,000 bbl/d (=452 x 10^9 x 0.30 x 0.25 x 24/5.5 x10^6).

c. The total oil displacement potential is thus about 340,000 bbl/d (= 190,500 + 148,000).

5. Costs

As mentioned earlier, retrofit costs are highly dependent on the individual boiler. Since it is a case-by-case item, generalizations are difficult if not impossible to make.

Studies conducted by Dravo and information from boiler manufacturers indicate that the cost of retrofitting of industrial boilers requires capital investment of $2500-4000/MMBtu/hr. These costs need to be added to the cost of the gasifiers and related equipment.

The cost of a gasification facility itself will depend on whether low- or medium-Btu gas is needed, facilities available and the degree of clean-up required for the gas. Using small gasifiers, and assuming utilities are available, the installed cost of a plant for producing a low-Btu fuel gas in 1982 dollars is $1.5 MM for a 1.5×10^9 Btu/day plant without any gas clean-up, which is suitable for process furnaces and kilns only. With tar and particulate removal as required by boilers the cost is $5.5 MM and ranges up to about $23 MM for a 9×10^9 Btu/day plant. The installed cost for a plant to serve a single 250 MMBtu/hr boiler is about $17 MM. These costs would increase by about 20 to 30 percent if medium Btu gas is required. Larger capacity plants based on Dravo data might cost $400 to 500 MM for a 100×10^9 Btu/day plant to produce a medium Btu gas with hydrogen sulfide removal. These large plants would be likely to serve a large industrial plant or complex and would not generally be geared to a single large user. The cost of low-Btu gasifier plants, in the 50 to 350 MMBtu/hr range, based on boiler capacity, is $62,000-88,000/MMBtu/hr.

The boiler efficiency and rated capacity will decrease while firing low-Btu gas. For screening purposes, an efficiency loss from 82 percent (while firing oil) to 75 percent (while firing low-Btu gas) and a capacity derating of 30 percent are assumed. Based on efficiency loss the gasifier capacity is higher than the boiler capacity by 82/75, but since the cost figures above are based on boiler capacity they need not be adjusted by this factor for determining the $/boe/d cost. With derating of the boiler when firing low-Btu gas, the industrial facility will require additional boiler capacity in order to achieve the historically required steam load with comparable reserve margins for reliability and maintenance. The installed cost of package boilers modified to fire low-Btu gas will be 7,000 to 19,000 $/MMBtu/hr boiler output in the size range of interest[8]. As an alternate to installing new boilers another option is to switch the boiler back to residual oil when load demand exceeds 70 percent of full load. However, depending on the type of load duration curve and capacity factor this option would result in an

inordinately large amount of the required Btu's generated from oil, typically in the 30 to 65 percent range.

Using a capacity factor of 35 percent, and totaling the cost of gasifier, new boiler and boiler retrofit, coal gasification for industrial applications entails capital in the range of

$47,000 to $73,000/boe/d =
[(71,500-111,000 $/MMBtu/hr)(5.5 MMBtu/boe)/35%x24hr/d].

The annual cost of coal gasification facilities is based on the fixed charges, fuel costs and O&M costs. The fixed charge is

$26 to $40/boe =
[($47,000-73,000/boe/d)(0.2%/yr)/365 day/year].

Based on coal at $2.25/MMBtu and 85 percent gasification efficiency, the fuel charge is

$16/boe =
[($2.25/MMBtu)(5.5 MMBtu/boe)(82%/75%)/85%]

O&M is assumed at 6 percent of the annual capital charge, bringing the total annual cost to $43 to $58/boe.

6. Non-institutional Contraints

The time required to design, build and commission large gasification plant may well be its most serious drawback for potential application in an oil cut-off. It may be possible to reduce the time for the installation of the small gasifier modules to 1 or 1 1/2 years if a "crash" program is instituted. The time requirement for the larger gasifiers might also be reduced in a "crash" program. Ways in which the time lag might be reduced in the crash program would be to pay higher prices for equipment to get preference on delivery, higher labor for overtime and waiving of environmental and other regulatory constraints. However, it will require more than four years before any displacement of oil can occur.

The availability of land may also be a constraint. If sufficient land is not available, the gas will have to be piped to the user. The practical transmission distances are limited, especially for low Btu gas. Land requirements are highly variable ranging from less than 1 acre for a single small gasifier module to over 100 acres for a large complex.

Coal supplies might also present a constraint. Although the coal industry is currently producing at less than capacity, widespread use of coal during an oil cut-off would probably

require investment in new mining operations. The development of new mines could take place as the gasifiers are built, if environmental constraints on the mines' development and operation did not seriously hinder the new mines.

Gasification plants often require large quantities of water. Adequate water supplies may not always be readily available. This is particularly true in the western United States where water is scarce and the water supply may be a serious constraint. Even those gasification facilities which treat and recycle waste waters usually have substantial make-up requirements. This can be alleviated to some extent by using air-cooled heat exchangers.

In a normal commercialization situation, there should be adequate supplies of equipment, building materials and skilled personnel to build and operate coal gasification plants. However, a rapid build-up following a loss of imported oil could create shortages of some materials and skilled labor.

7. Regulatory Constraints

The primary constraints in this category are environmental. Numerous environmental permits are required by Federal, state and, in some cases, local agencies. Although the use of fuel gas instead of oil will result in no increase in emissions from the boiler, the design and operation of the gasification plant will have to satisfy a number of requirements.

Atmospheric emissions will have to satisfy New Source Performance Standards and Prevention of Significant Deterioration Permit Requirements. The latter may also require one year of air quality monitoring prior to submitting the application. Preparation and approval of an Environmental Impact Statement (EIS) may also be required and this is another time consuming item. Considerable time could be saved by eliminating the atmospheric sampling and by fast-tracking the EIS.

Permits to use water from rivers or lakes must also be obtained and the impact of its use must be shown to be acceptable from an environmental viewpoints.

The discharge of aqueous wastes must also be permitted. Obtaining these permits is time consuming and often requires a considerable invetment in equipment.

The disposal of ash or char and any other solid wastes (sludges or catalysts) must also be done in an environmentally acceptable manner. Since there is currently little commercial gasification taking place, there could be serious delays in getting a determination on whether a waste

is hazardous or non-hazardous. If too many wastes are deemed hazardous a shortage of suitable landfills could present problems.

In order to construct gasification plants in significant numbers in a reasonable time, some relaxation of the permitting requirements would be necessary. This does not necessarily mean permitting high pollutant discharges, but rather entails streamlining the cumbersome permitting processes.

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G. COAL LIQUEFACTION

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1. Introduction

Technology exists to convert coal into liquid fuels ranging from synthetic crude oils to specific compounds such as methanol. Such liquids are capable of supplementing petroleum products in all areas of application. While commercial facilities for liquefaction exist in a few parts of the world, the cost of the products is high and large amounts of capital and time are required to put such facilities in place.

2. Description

Coal liquefaction is a broad-based technology. Coal liquefaction processes may be divided into several classifications:

a. Hydroliquefaction

Feed coal is mixed with a hydrogen containing gas and reacted at elevated temperatures and pressures. The reaction is either non-catalytic, pseudo-catalytic or catalytic. Depending on the conversion conditions used primary reaction products may be solid or liquid at room temperature. The Solvent-Refined Coal (SRC I and II), and H-Coal processes are examples of hydroliquefaction.

Hydrogen may also be supplied by a highly hydrogenerated liquid called a donor solvent. Since the solvent is rich in hydrogen, it transfers hydrogen to the coal during the liquefication process. Part of the coal which remains undissolved is gasified to yield additional hydrogen. The Exxon Donor Solvent process is an example.

b. Pyrolysis

Feed coal is heated to an elevated temperature to produce gas, and tar which can be hydrotreated to produce low sulfur liquids and char. Solid char and gases may be converted to hydrogen for hydrotreating or syngas for indirect liquefaction. Coking of coal and the COED processes are examples of pyrolysis technology.

c. Indirect Liquefaction

Coal is partially oxidized in presence of oxygen and steam. The reaction generates a gas consisting mainly of carbon monoxide and hydrogen. After purification, the gas may be catalytically converted to liquid fuels

by one of two major routes, Fischer-Tropsch synthesis or methanol production purification.

Gasification of coal is an intermediate step in the indirect process for producing liquid fuels from coal. There are several commercially proven processes presently available for coal gasification.

These processes are:

- Lurgi's Pressure Coal Gasifications
- Koppers-Totzek
- Winkler
- Wellman-Galusha.

These process are currently being utilized in foreign countries for the production of synthesis gas. Lurgi's Pressure Coal Gasification Process with the Fischer-Tropsch synthesis is used in the world's only commercial synthetic liquids plants currently operating - Sasol I in Sasolburg, and Sasol II & III in Secunda, South Africa. The coal gasification technology is described in Appendix F of this report and only the conversion of synthetic gas to liquid fuels via the Fischer-Tropsch or methanol reaction are described below.

1) Fischer-Tropsch Process

A simplified flow diagram of the Fischer-Tropsch process is shown in Figure G-1. The process yields a mixture of hydrocarbons, alcohols and other chemicals.

In the Fischer-Tropsch process two types of commercial reactors are used.[2] Fixed bed reactors each consist of over 2000 tubes 40 ft. long and 2 in. ID. The tubes, which contain catalyst, are surrounded by boiling water. Temperature is controlled by regulating the generated steam pressure. Both a high conversion and a high gas linear velocity can be attained by feeding fresh synthesis gas as well as recycling tail gas.

The latter ensures that the heat of reaction is rapidly removed along the length of individual reactor tubes resulting in a near-isothermal reactor. Alternatively, Synthol reactors (Figure G-2) can be used. These reactors are of the transported and fluidized type. Feed gas enters at the bottom and meets a stream of down flowing hot catalyst from the standpipe which heats gas to its ignition temperature. The highly turbulent flow of catalyst and gas passes through two banks of heat exchangers to the wide settling hopper above the standpipe where gas and catalyst disengage. Gas and hydrocarbon vapors leave the reactor via cyclones which remove entrained fine catalyst particles and return them to the settling hopper. Internal heat exchangers remove about 35 percent generated heat. The balance goes out with recycled gas. Because of the high turbulence the radial temperature gradient is low. Exit temperatures are typically 600 to 675 F. Process conditions are geared for products that are gaseous under reaction conditions.

Although ruthenium, nickel and cobalt are very active catalysts for Fischer-Tropsch reaction, catalysts used in Sasol commercial reactors are iron-based and consequently are much cheaper. The main reason for using iron, however, is that at similar conversion levels it produces less methane and more olefins than the other metal catalysts.

Production of olefins, besides being valuable in their own right as petrochemicals and for production of polymers, makes the whole process more flexible since a few olefin molecules can be readily combined (oligomerized) to either the gasoline or diesel range depending on the relative demand for these two motor fuels.

Catalysts used in fixed bed reactors for wax making are prepared by precipitation. Iron oxide is supported on silica gel and promoted with an alkai.

The catalyst used in synthol reactors is prepared by fusing iron oxides found in some millscale from steel mills or iron ores. The type and amount of impurities in the raw iron oxide must not exceed certain limits.

Figure G-1

Simplified Block Flow Diagram
Fischer-Tropsch Process

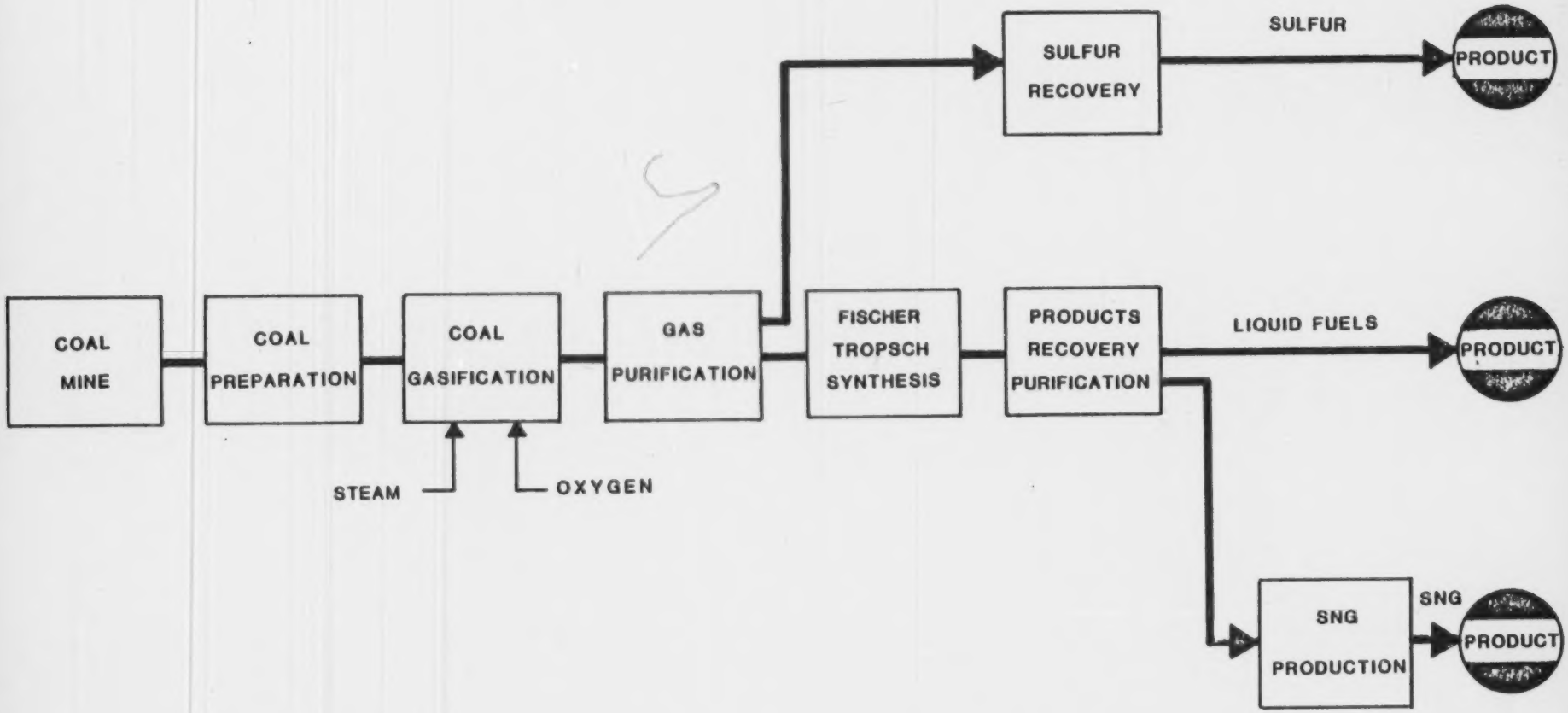
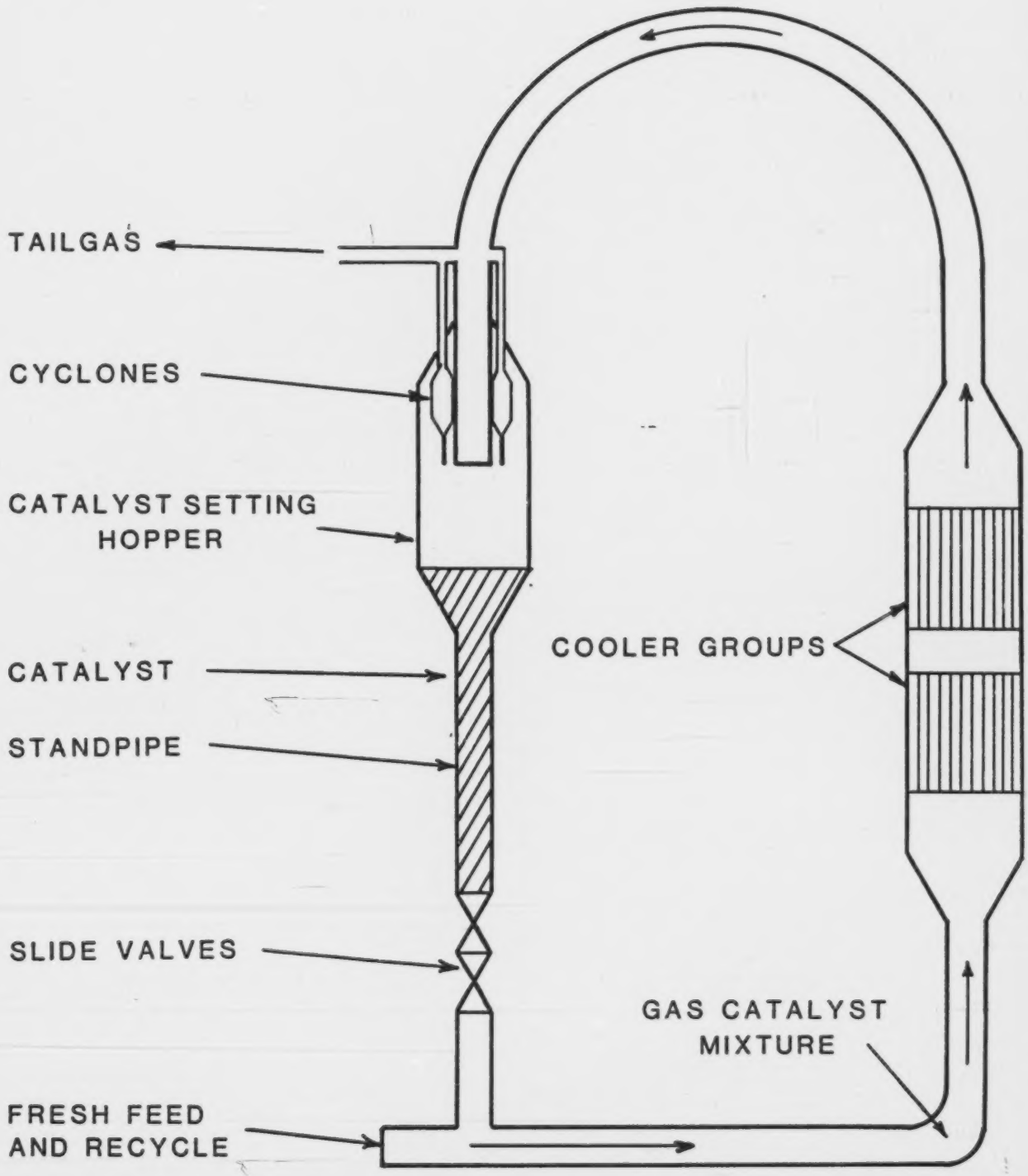


Figure G-2
Synthol Reactor



This type of catalyst is relatively cheap to manufacture. Required promoters are usually added during fusion. Ingots are milled down to the prescribed particle size and reduced with hydrogen. Particle size control is important to optimize fluidization quality essential for smooth reactor operation.

Products from the Fischer-Tropsch processing can be selectively varied over a wide range. Depending on the type of reactor chosen and conditions of operation, either gasoline or diesel components can amount to as much as 75 percent of the hydrocarbon produced.

Reactor effluent gas is quenched in a scrubbing tower where the remaining catalyst dust is removed and returned to the reaction zone in the form of a heavy slurry oil.

The raw products from the synthesis require certain treatment and then final purification to make the specification products. From the gas phase, valuable hydrocarbon and chemical products are scrubbed out and recovered. The oil phase is treated catalytically to remove dissolved oxygenates and then distilled into gasoline and fuel oil fractions.

2) Methanol Synthesis

Methanol can be produced from syngas by several commercial processes:

The overall block flow diagram for coal to methanol is shown in Figure G-3.[7]

The gasification products from Lurgi, Koppers-Totzek, and Winkler coal gasification processes can be used for methanol synthesis. The composition of the gas produced in the gasification process will vary with the type of gasifier used and the coal processed. Therefore, the overall process for methanol synthesis will vary to some degree. The gasification step produces H_2S and COS compounds which are poisonous to the downstream methanol synthesis catalyst. Therefore, acid gas removal and sulfur recovery processing areas are required. The amount of hydrogen produced in gasification is not sufficient for methanol

synthesis. Therefore, water gas shift conversion ($CO + H_2O = CO_2 + H_2$) is required.

Methanol synthesis consists of compressing (if required) the makeup gas, mixing the makeup gas with recycle gas and then feeding the mixture to the methanol converter, a vessel containing several beds of catalyst. The two overall reactions occuring in the converter are those associated with the combination of hydrogen and carbon monoxide to form methanol and the reaction of hydrogen and carbon dioxide to form carbon monoxide and water (reverse shift reaction).

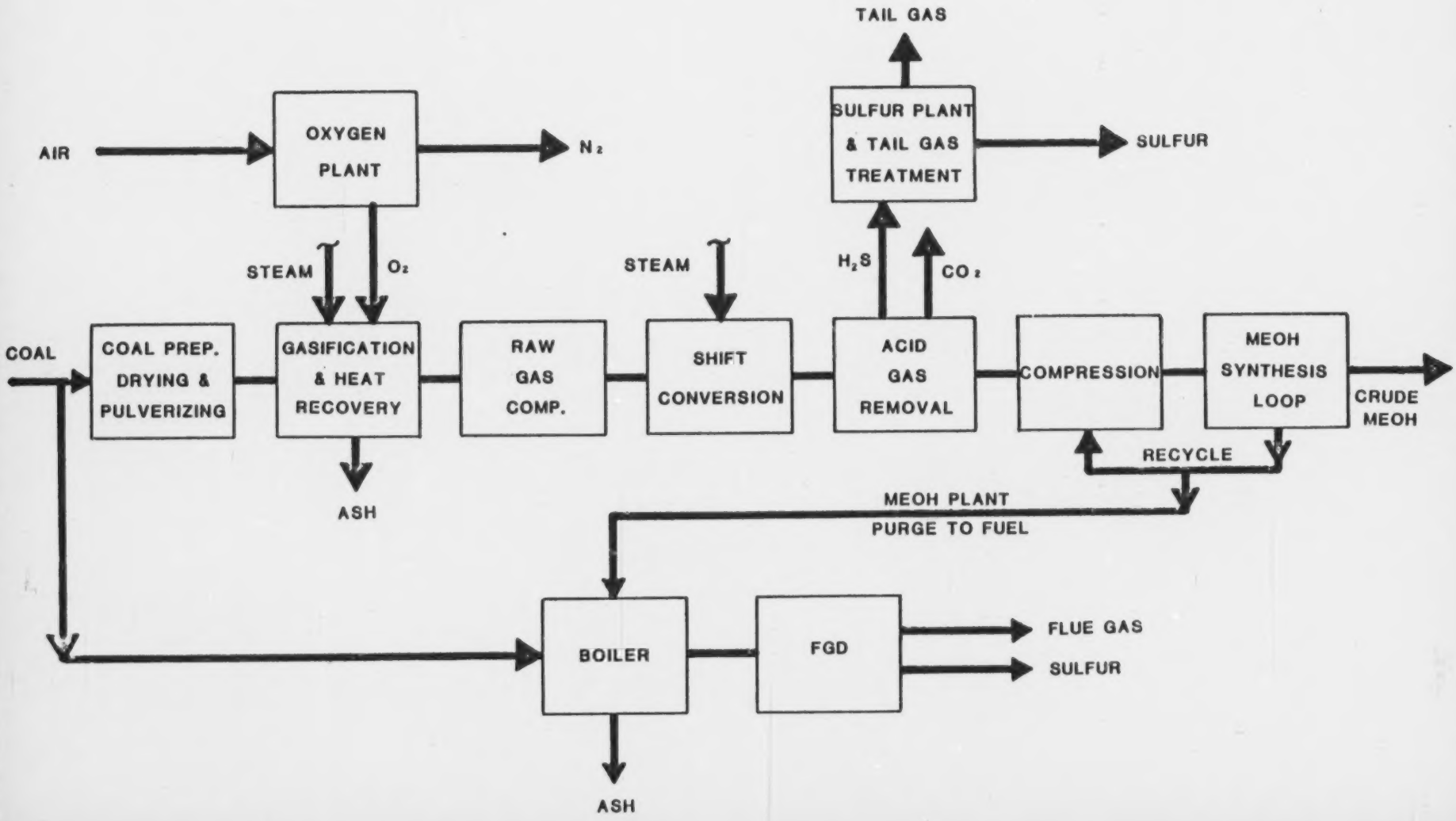
$$CO + 2H_2 = CH_3OH$$
$$CO_2 + H_2 = CO + H_2O$$

The copper based catalyst is used in the methanol converter, because it is more active and more selective producing smaller quantities of byproduct and requires lower pressure operation than that for the zinc oxide/chromia catalyst. The methanol converter operates at 400 F-575 F.

The yield of methanol is estimated at about 200 gal/ton of coal.

Figure G-3

Simplified Block Diagram Coal To Methanol Process



3. Commercialization Assessment

Germany and the Republic of South Africa, and to a lesser extent the United states, the United Kingdom, France and Japan have built and operated coal liquid producing facilities.[3] Basic pioneering work was done in Germany in 1911. Fischer-Tropsch reported on synthesis of aliphatic hydrocarbons from carbon monoxide and hydrogen mixtures in 1925.[4]

By 1945 there were 18 hydroliquefaction plants in Germany with a capacity of more than 4 million metric tpy (mtpy). Parallel development of Fischer-Tropsch technology led to construction of the first commercial plant in 1936. In 1939, nine plants existed in Germany with a total rated capacity of about 750,000 mtpy of liquids.[5]

In the United States, Union Carbide operated a semi-commercial coal conversion unit at Institute, W. Va. and the U.S. Bureau of Mines operated one at Louisiana, Mo., from 1949 to 1954.

The indirect coal liquefaction featuring Lurgi dry-bottom gasifier and Fischer-Tropsch process is the basis of the world's only commercial synthetic-liquids plants currently operating - Sasol I, a 25 year old unit in Sasolburg, South Africa. This plant now produces waxes, liquid fuels, pipe line gas and chemicals.

The unit of South Africa Coal, Oil and Gas Corporation Ltd. (Sasol) has built a larger facility, Sasol II, at Secunda which came onstream in 1980. A third plant, Sasol-III at Secunda, is virtually identical to Sasol-II. The two new plants produce predominantly ethylene, gasoline and diesel. Each plant will have 36 gasifiers (that feed on some 40,000 tons/day of subbituminous coal) and 7 Synthol reactors. The output will be more than 50,000 bbl/day of fuels per plant.

4. Oil Replacement Potential

The conversion of coal to gas and oil requires the construction of large and costly facilities. Design and construction of the coal liquefaction plant using Lurgi process with Fischer-Tropsch synthesis will take at least 6-8 years. Within a 5-year framework it will not be possible to replace significant quantities imported oil with coal-derived liquid fuels.

5. Cost

The coal liquefaction plants capable of producing premium fuels must have high throughput rates and low capital costs to produce liquid fuels economically. A plant processing 20,000 to 40,000 tons of coal per day will cost several billion dollars.

In the mid-70's a study was made on conceptual design and economic evaluation of a small plant to process 4,600 tons/day of coal and produce 2,500 bbl/day of liquid fuels plus about 60 million scf/d of substitute natural gas (SNG).

Preliminary results on the potential use of Fischer-Tropsch technology in the United States indicate that a small plant based on the process is not attractive based on current economics, but that a very large facility could offer more interest.[6]

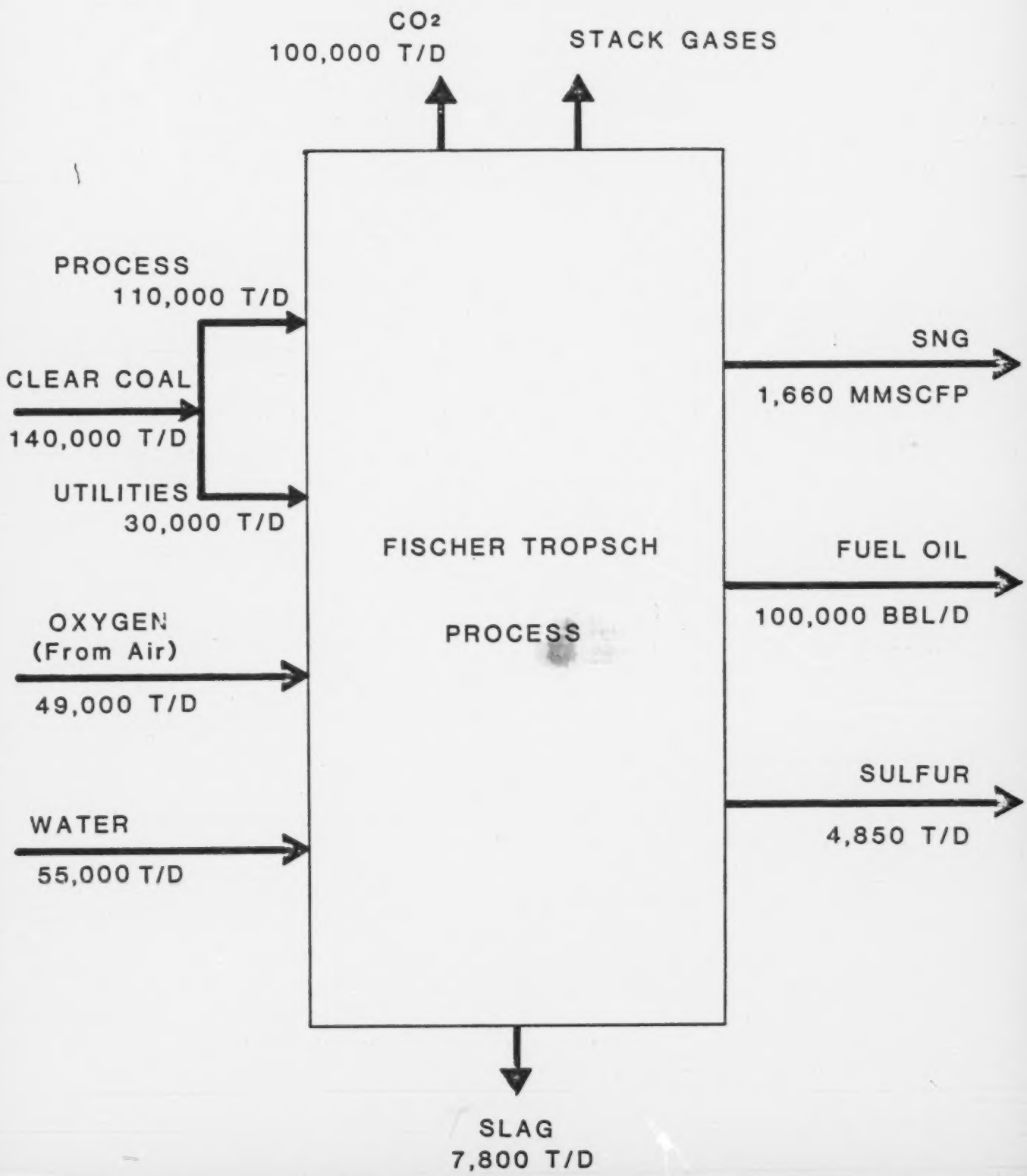
A second study developed a possible configuration and approximate economics of a large Fischer-Tropsch Complex. Overall material balance for this large plant is shown in Figure G-4. We see that 140,000 ton/day of coal are used to produce 100,000 bbl/day of fuel oil plus approximately 1,700 million scf/day of SNG and somewhat less than 5,000 ton/day of sulfur. Oxygen and water requirements are approximately 50,000 and 55,000 ton/day, respectively.

Judgmental estimate is that the fixed capital investment for the 100,000-bbl/day Fischer-Tropsch plant might be $2.8 billion, based on first quarter 1975 cost. In mid-1982 dollars, the plant cost would be about 4.5 billion based on the CE Plant Index or 45,000 $/bbl/day. A 65,000 bbl/day facility has been estimated at 75,000 $/bbl/day.[10]

Current cost of Fischer-Tropsch synfuel production with crude oil at $30/bbl is estimated to be in the $140-$160/boe range compared to the not-yet commercial synfuel processes such as H-coal and donor solvent which are in the $60 to $70/boe range.[9] Furthermore, as the price of oil rises the price of the synfuel remains higher than the oil price, even at $100/bbl. This means that coal liquids plants may not be economic as an investment project even under the oil disruption scenario. The plants may only be economic under a scenario where the plant is built under current economic conditions ($30/bbl oil) in anticipation of $100 to 200/bbl oil by the time the plant is operational.

Figure G-4

Overall Material Balance, Large Fischer Tropsch Plant



A number of studies evaluating the economics of converting coal to methanol have been published.[8] Based on a study by the Kentucky Department of Energy[8], the 1977 economics for a large coal to methanol plant are summarized in Table G-1. Based on this data and more recently published data[9,10], the mid-1982 capital investment and annual costs are estimated to be about $60,000/boe/d and $80/boe, respectively.

6. Non-institutional Constraints

The lead time for the design and construction of coal liquefaction plant is about 6-8 years. This is a major constraint for rapid deployment of this technology during the five-year oil cutoff scenario.

Many of the other constraints are similar to those described for the shale oil technology (see Appendix H).

7. Institutional and Regulatory Constraints

As is inevitable with almost any industrial plant of significant size and complexity, synthetic fuel plants will disturb the land, add emissions to the atmosphere, and affect water availability and possibly quality. The magnitude of environmental change will depend on the size of the industry and the degree of environmental control measures employed. The federal, state and local regulations concerning air, water and particulates emissions will be the most important constraints.

Since large volumes of solids are involved, particulate emission relative to mining, crushing and grinding, and transport are of major concern. Disposal of slag from the coal liquefaction process is a significant problem. The landfill area must be available for its disposal. The problem of possible carcinogenic and mutagenic effects of polynuclear aromatics is not as severe in Fischer-Tropsch synthesis compared to other direct coal liquefaction processes. Coal liquids boiling above 480 F contain predominantly multi-aromatic rings. Thus care will have to be utilized in the production refining and use of the heavier fractions.

TABLE G-1

SUMMARY ECONOMICS FOR A LARGE COAL TO METHANOL PLANT

Coal Consumption	: 20,000 tons/stream -d
Methanol Production [1]	: 100,000 bbls/stream -d
Capital Investment [2]	: $1.95 billion
Annual Cost[3]	
Coal @ $20/ton	: $132 million
Utilities, Catalyst and Chemicals	: $ 18 million
Operation and Matinenance	: $ 63 million
Capital Related Charges[4]	: $390 million
Total Annual Cost	: $603 million, or
	: $43/gal methanol[5], or
	: $7.0/MMBtu, or
	: $37.8/boe

Notes:

[1] 210 gals of methanol per ton of coal.

[2] "Instant Plant" cost in 1977 dollars ($1.3 billion) plus 50 percent for interest during construction.

[3] 1977 dollars based on 330 stream days per year.

[4] Estimated at 20 percent annual fixed charge rate.

[5] 63,000 Btu per gal of methanol.

Source: Adapted from Reference 8.

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H. TAR SANDS AND OIL SHALE

PART 1: TAR SANDS

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2. Description of Available Technologies
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5. Costs
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H-1-2 Flow Diagram - Retort Process for Tar Sands
H-1-3 Flow Diagram - Percolation Extraction of Tar Sands
H-1-4 Flow Diagram - Emersion Extraction of Tar Sands

1. Introduction

Deposits of mineable diatomaceous earth, sand, soft limestone, soilstone, etc., impregnated with enough crude oil to make recovery economically feasible, are located in several areas of North America. These deposits contain enough bitumen to displace large quantities of crudes now derived from other sources.

The recovery of the crude oil from these deposits is achieved by employing one of three general processes or combinations thereof, all of which are in various stages of commercialization.

These processes may be categorized as follows:

a. Hot Water Leaching

b. Thermal Processes

c. Solvent Extraction.

While the bitumen recovered from these deposits generally requires further upgrading steps, it can then be used in place of crude now being processed. Technology for upgrading is available and already in use in the industry.

2. Description of Available Technologies

Three major processes or combinations thereof are currently available to recover crude oil, or bitumen, from tar sands. Each of these processes are in various stages of commercial development.

a. Hot Water Process

By far the most common process for recovery of bitumen from surface mined tar sands is the hot water process. It is primarily used on the athabascus sands but it can be used on other water wetter or hydrophilic sands. The process is shown schematically in Figure H-1-1.

In this process, tar sand which has been size reduced and screened is fed to a conditioning drum where it is mixed with water and sodium hydroxide. Steam is injected into the slurry in the drum to raise it to the operating temperature of 175-200 F. The slurry, containing about 60-85 percent solids, is then screened to remove coarse particles. The screened slurry is then mixed with hot water and pumped to the separation cell along with a recycle stream of fines, bitumen and water

from a clean up stream. The sand particles, which are wet with water, settle to the bottom of the cell while the bitumen rises to the top, and an emulsion of fines, bitumen and hot water forms in the middle of the cell. A second stream which is a slurry of water and fines enters the bottom of the cell. From the cell, bitumen overflows to the production recovery section of the process.

The sand-water slurry from the bottom of the cell is pumped to a tailing pond for separation by settling and water disposal. The cell middling, which is the emulsion layer, is withdrawn to scavanger cells where air is injected to separate the bitumen layer from the water and fines. The bitumen layer overflows to further scavenging prior to overflowing to a deaerator then to bitumen product. The fines and water from the initial scavenging step are recycled to the bottom of the separation cell while the fines water slurry from the final scavenging are recycled and mixed with the main feed stream.

While this is a very simple process, it has not been totally effective in the separation of fines from the bitumen, or fines and bitumen from the water. The overall bitumen recovery is about 65 percent.

The major disadvantages of this process are as follows:

1) The tailings stream contains sand and fine clay mixture which has very poor settling characteristics. This necessitates the construction of extremely large tailings ponds.

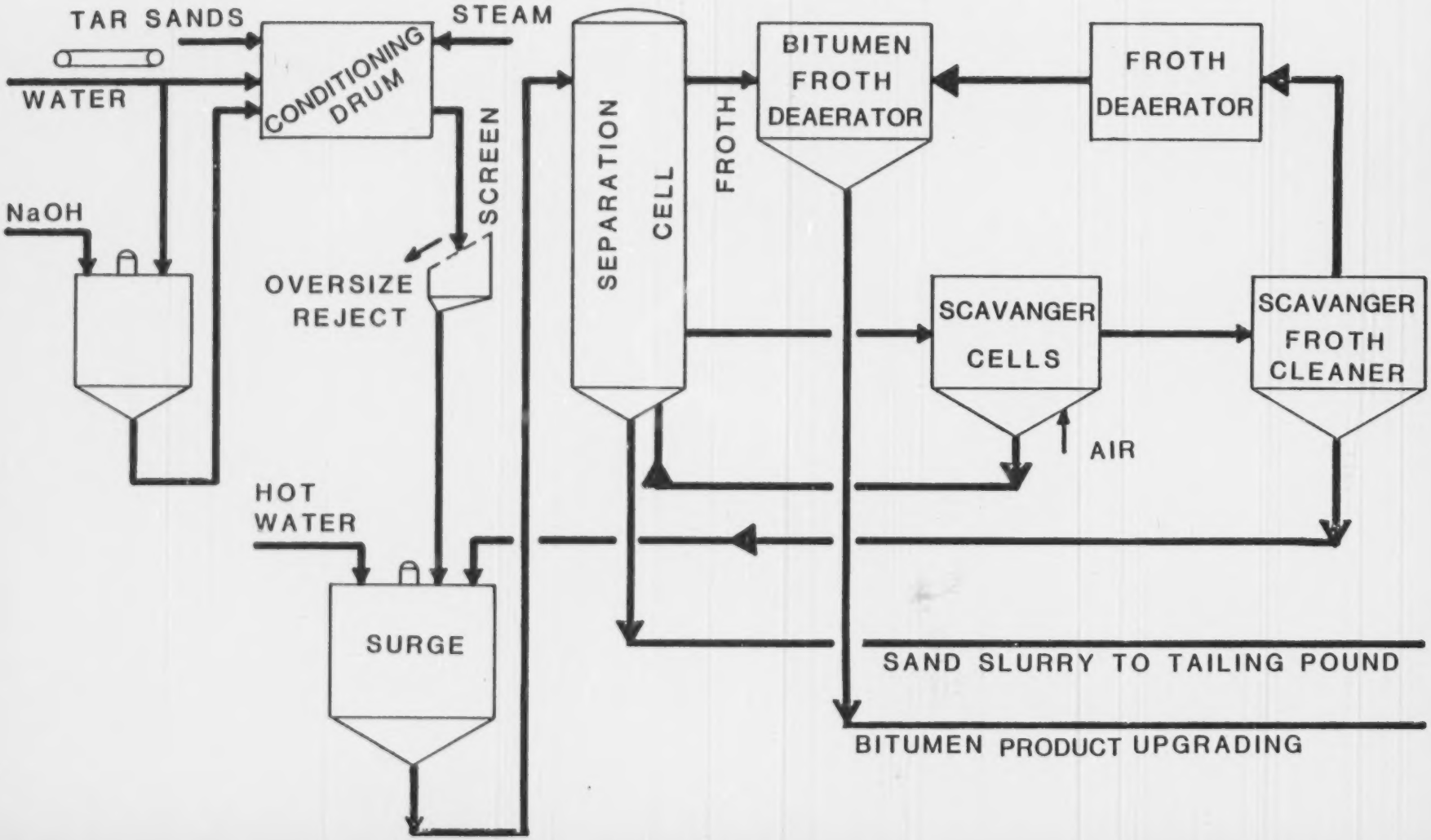
2) Approximately 10 percent of the bitumen in the feed is lost to the tailings stream.

3) Large amounts of water and steam are required in the conditioning step.

4) Large amounts of energy are required for the production of hot water and low pressure steam.

Figure H-1-1

Flow Diagram- Hot Water Process For Tar Sands



b. Thermal Process Technology

The most advanced process in this category is the retort process shown schematically in Figure H-1-2. Spent sand at 1200 F from the collection bin is blended in the mixer with the sand from the feed dryer resulting in a retorting temperature or about 900 to 1000 F. From the mixer the mixed sand drops to a surge hopper where the product is withdrawn thorugh cyclones and dust scrubbers as a gas and subsequently condensed in the product recovery systems. The gas product is collected and stored in gas holders or recycled to provide some of the fuel for the lift heater. The condensed liquid containing a large fraction of super fine material from the scrubber is sent to a solids separation system. The liquid product is pumped to storage while the solids are fed into the recycle stream back to the lift heater. In the surge hopper following the mixing and retorting step, the stream of sand is split. Part of this steam is returned to the lift heater while the remaining portion is sent to the air preheater. This recycled sand has coke deposited on it following retorting. This is burned off in the lift heater.

The major disadvantages of this process are:

1) Severe heat loss in the spent sand.

2) Small unit throughput and poor scale-up economics.

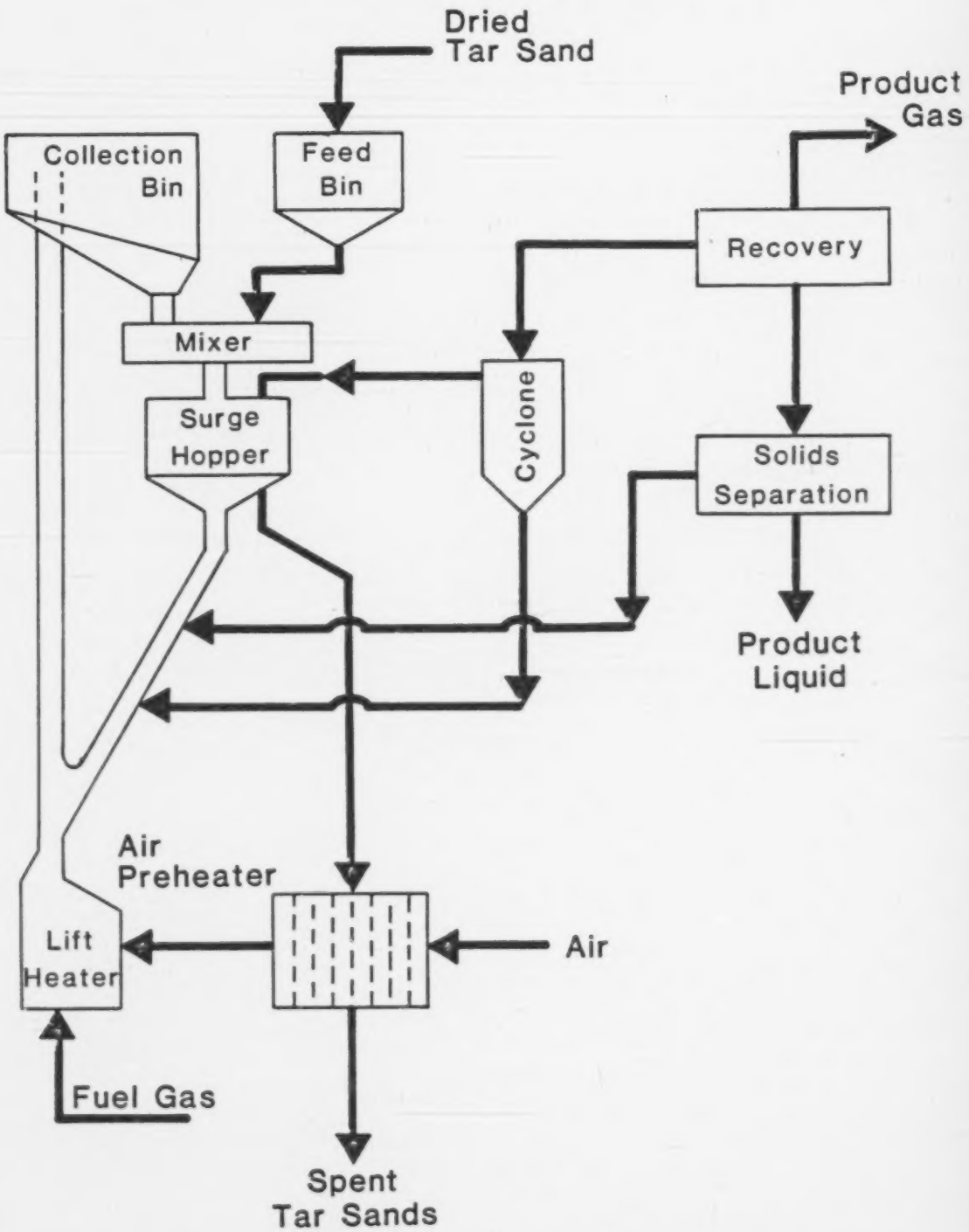
3) Expensive construction and replication of retorting equipment.

4) Preparation and handling of tar sand feed.

5) Extreme errosion in fines separation step.

Figure H-1-2

Flow Diagram Retort Process For Tar Sands



c. Solvent Extraction Technology

The countercurrent percolation process is used on hydrophylic sands which can be agglomerated. The beds are formed in the baskets of a continuous horizontal extractor then countercurrently subjected to washing with streams of solvent and bitumens, termed miscella. Each stream of miscella contains a lower concentration of bitumen until the final wash is clean solvent.

The second solvent extraction process which may be employed to recover bitumen from the tar sands is an emersion process. This process is normally used when the feed material cannot be agglomerated into a percolable bed, or in cases when fines are present in amounts sufficient to reduce the porosity of the beds upon reincorporation so that percolation cannot be accomplished. This process is also a countercurrent washing process.

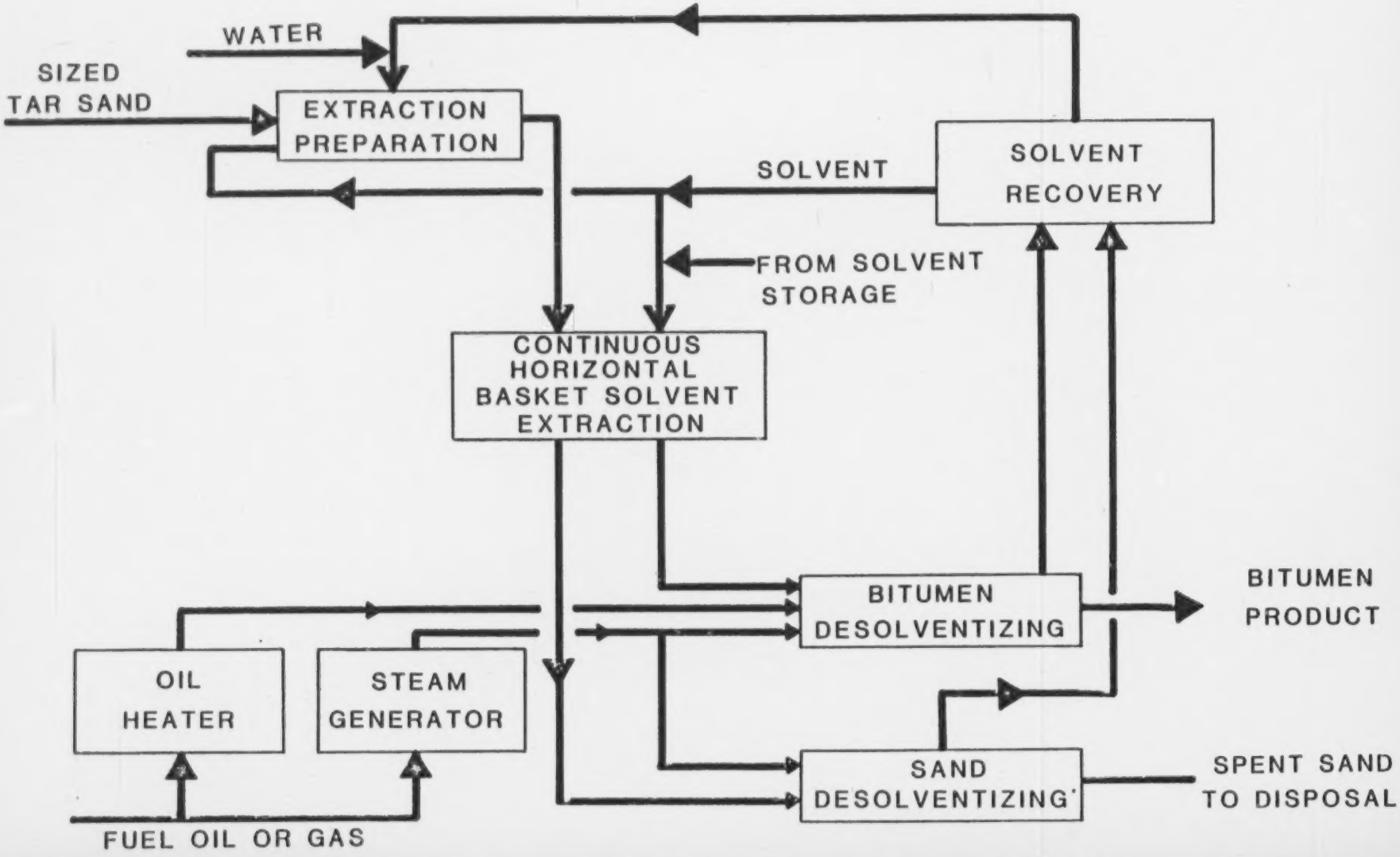
Neither of the two processes has been commercialized. However, both processes will be tested in pilot units having substantial production capabilities during 1983.

d. Percolation Extraction

The percolation extraction process is illustrated in Figure H-1-3. Sized tar sands from the crushing system are fed to the extraction preparation system where they are contacted with hot solvent and water. Most of the surface bitumen is dissolved in this step and the sand is wetted so that it is percolable. Following this mixing, the slurry is classified and the heavy slurry is pumped to the continuous extractor where it is continuously washed with miscellas of decreasing bitumen concentration; then the final wash is done with clean solvent. From the extractor the spent sand is conveyed to the sand desolventizer while the strong miscella is pumped to the bitumen desolventizing system. Vapors from these two desolventing steps are condensed in the solvent recovery system. The solvent is recycled to the extractor and to the extraction preparation step.

Figure H-1-3

Flow Diagram For Percolation Extraction Of Tar Sand



e. Emersion Extraction

The emersion extraction process is illustrated in Figure H-1-4. Crushed and screened tar sands are conveyed to the mixer where it is mixed with strong miscella from the second extractor overflow. This mixed slurry is pumped continuously to the first extractor where solids settle to the bottom while relatively clear miscella overflows to the miscella clarifier. The concentrated slurry from the first extractor is pumped to the second extractor via an inline mixing device where miscella from the third extractor is mixed with it. In the second extractor the miscella overflows to the mixer while the solids settle to the bottom forming a concentrated slurry which is pumped to the third extractor after being mixed with miscella from the fourth extractor. This counter current washing continues through the required number of washings until clean solvent is used in the final wash. From the final extractor the concentrated slurry is pumped to a disengager where water is used to displace the solvent in concentrated slurry phase. The overflow from the disengager goes to the next to last extractor where it is joined by the miscella overflow from the final extractor. The concentrated solids from the disengager, now is water slurry, is pumped to the sand desolventizer where solvent is stripped from the slurry. The stripped solids are then filtered with the water being recycled to the disengager while the solids are sent to disposal. Vapors from the desolventizer are utilized as a heat source in the desolventizing of bitumen. From the miscella clarifier miscella is filtered and the solids washed free of bitumen. They are then reslurried in water and pumped with the disengager bottoms to the sand desolventizer. The bitumen is pumped to the bitumen desolventizing system where the solvent is evaporated and stripped from the bitumen. The bitumen is pumped to product storage while the solvent and water vapors are condensed and recycled.

The yield from both solvent extraction processes should exceed 85 percent of extractable materials.

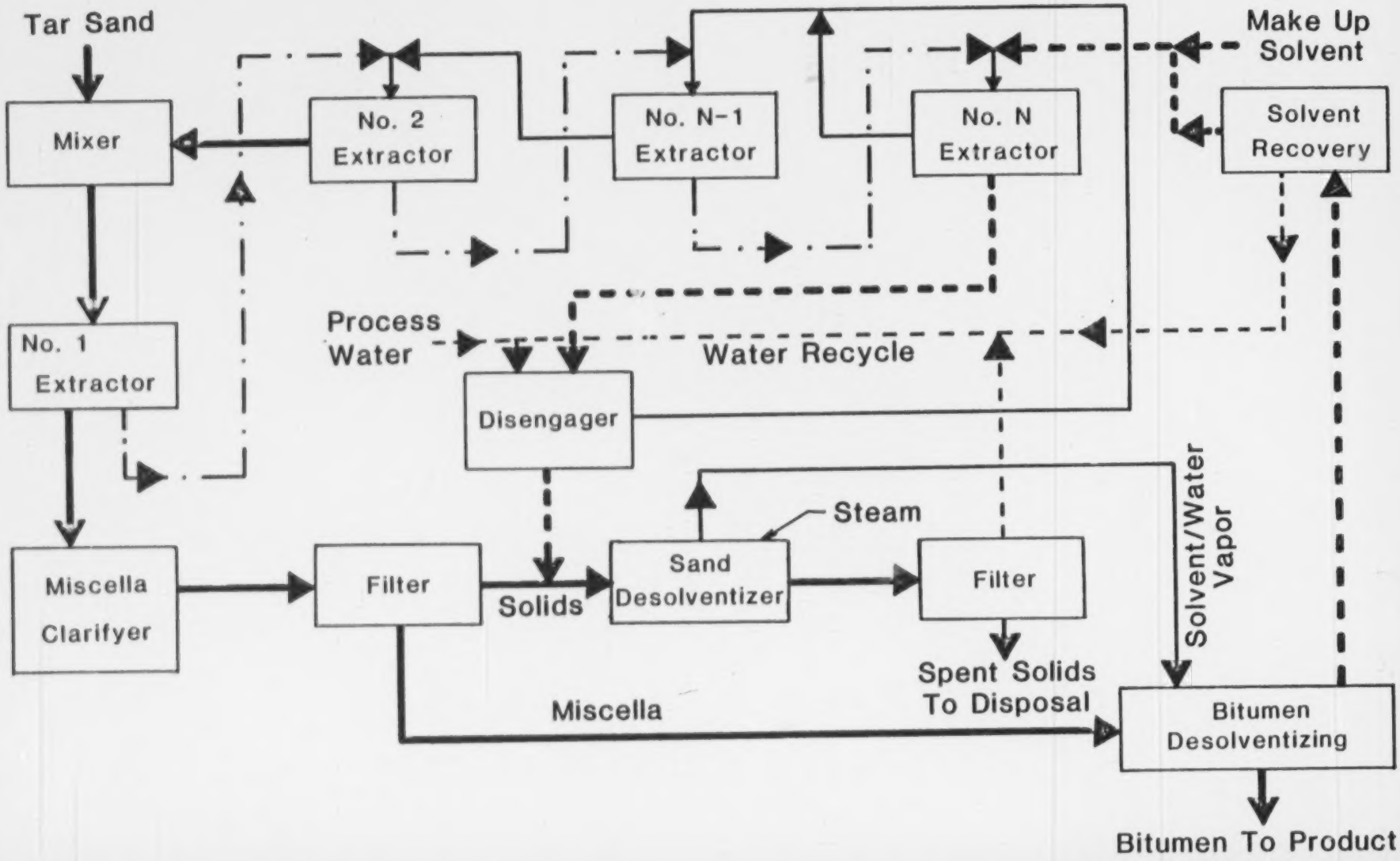
The major disadvantages of the above solvent extraction processes are:

1) Difficult control of fines.

2) Loss of solvent in spent sand.

Figure H-1-4

Flow Diagram For Emersion Extraction Of Tar Sands



3. Commercialization Assessment

The commercial status of the various technologies is as follows:

Process	Concept	Bench Scale	Pilot Plant	Commercial
Hot Water	x	x	x	x
Retort	x	x	x	
Percolation Extraction	x	x	1983	
Emersion Extraction	x	x	1983	

4. Oil Replacement Potential

Following upgrading and further processing the bitumen from these processes can be utilized as a replacement for any of the current crudes. Oil from tar sands generally have gravities ranging from 6°API to as high as 19°API. The current in-place bitumen resource in the U.S. is estimated to be 30 billion barrels, while Canada estimates its reserves to be 965 billion barrels.

Although there are two commercial plants operating in Canada, there is not sufficient experience to permit a surge deployment of these facilities during an oil cutoff. Based on this and the long lead time for a large scale commercial facility, the oil replacement potential for tar sands in the 5-year period is not significant.

5. Costs

Reliable cost information on tar sands production facilities is limited because of the technology status and the fact that much of the development has taken place in Canada. Based on a study published by the Canadian Department of Energy, Mines, and Resources in 1977, the mid-1982 capital investment for a hot water process facility is estimated to be in the $36,000 - $45,000/boe/d range with a product cost of $22-$28/boe.

Plants are operating today and producing at this product cost level. However, newly proposed tar sands projects in Canada have been burdened by additional federal and provincial royalties which has led to their cancellation since the projected price of the extracted oil is not competitive with current and projected crude oil prices. In the U.S.,

investment costs and product costs are expected to be higher not because of excessive royalties but rather because the tar sands sites are in relatively inaccessible locations and require development of a infrastructure near the resource.

The solvent extraction techniques in large scale projects have been estimated at $8,000 to $10,000/boe/d with correspondingly low product cost, but these processes are just beginning pilot scale testing in 1983 and remain to be proven on a large scale.

6. Constraints

Besides the limited commercial status and long lead requirements, the principal restraint on all of the processes is lack of water in the area of the deposit and the lack of a developed infrastructure near the resource.

Furthermore, each of the processes are subject to major environmental constraints.

The hot water process is subject to codes covering handling and storage of flamable liquids as well as environmental codes covering air and water pollution. The tailing ponds, even though very large, still do not prevent unsettled fines and oil slicks from being returned to the natural watershed. Additionally these ponds represent a source of air pollution and could violate codes pertaining to odor control.

The retort process is subject mainly to environmental codes pertaining to air pollution. In spite of the precautions to prevent air pollution, both fines and hydrocarbons escape to the atmosphere. Codes covering handling and storage of flammable liquids also apply for this process.

While water pollution will be minimized as it is nearly 100 percent recycled, environmental codes related to ambient hydrocarbon release from process machinery and from spent sand, present the greatest constraint for solvent extraction processes.

7. References

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H. TAR SANDS AND OIL SHALE

PART 2: OIL SHALE

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H-2-1 Pyrolysis and Oil Recovery Unit: Tosco Process

1. Introduction

Oil derived from shale is capable, with proper refining techniques, of providing all liquid fuels which are ordinarily derived from petroleum. U.S. resources of oil bearing shale far exceed petroleum reserves. Oil has been produced commercially in the U.S. and elsewhere in the world although on a small scale. Several modern recovery processes have been successfully piloted, and design is underway for large commercial scale plants.

2. Description

a. Mining

Although the broad categories of technologies used to mine oil shale are similar to those used in mining coal, the actual operation and specific equipment items in an oil shale mine differ significantly from coal mining, primarily because the characteristics of the two resources are quite different. For example, oil shale deposits are often much thicker than coal seams, and oil shale is considerably harder than coal.

Like coal, oil shale can be mined either underground or from the surface. Although there is no commercial oil shale mining operation in the U.S. at present, two prototype underground mines have been developed and the techniques used in these mines are believed to be feasible on a commercial scale. Surface mining of oil shale has not been attempted in the U.S., but two of the four tracts leased in the prototype leasing program are expected to be mined from the surface.

No mining is necessary if a true "in-site" process is used to recover the oil.

b. Oil Recovery

Significant concentrations and grades of oil shale, as determined by standards tests, are as follows:

1) Typical shale contains 28 gallons of oil per ton

2) Maximum oil content may be 40 gallons per ton or more

3) Minimum economically recoverable content is 12 gallons per ton.

Oil recovery is accomplished by thermal decomposition or retorting. It is necessary to decompose the kerogen (a complex hydro-carbon substance) diffused in shale. Some characteristics of retorting are as follows:

1) Decomposition temperature is 900 to 1,000 F

2) Decomposition products of kerogen are:

- Large quantity of oil as micron-sized droplet in a gas stream
- Significant amount of low-Btu gas
- Residual carbon in spent shale.

c. Retorting Processes

Retorting may be accomplished either on the surface after mining or underground (in-situ). True in-situ processes involve heating shale in place by electromagnetic or acoustical means. Only minor mining operations, such as drilling or fracturing to permit oil collection are needed. Such processes are not well advanced.

Modified in-situ retorting requires mining out a portion of the shale, and

1) Fracturing the shale body and processing the fragmented shale in place

2) Introducing oil into top of retort and igniting it

3) Pulling a heat front down through the shale and collecting oil at the bottom.

The Occidental Petroleum Company has conducted large scale demonstration tests of this technology. The mined out portion of the shale represents 10 to 20 percent of the shale body and may be processed by surface retorting techniques or discarded.

A number of processes have been developed and tested to retort the shale mined from the ore body and brought to the surface. These processes can be grouped as follows:

1) Processes using solid heat transfer medium

   a) The Lurgi process uses 6 tons of sand per ton of shale to accomplish retorting

b) The TOSCO process (Figure H-2-1) uses ceramic balls transferred between the shale and heat source.

Both processes produce medium-Btu gas but have materials handling problems inherent in use of solids as heat carriers, particularly at the processing rates of commercial-size plants.

1) Processes using gas as heat transfer medium:

a) The Paraho and Union processes use shaft furnaces for retorting and have the scale-up problems that were evident in the early days of the iron ore pelletizing industry.

b) The Dravo and Superior processes are based upon traveling-grate pyro-processing technology proven by 20 years experience in pelletizing and sintering plants.

d. Oil Treatment and Properties

Table H-2-1 shows properties of raw shale oil and synthethic crude oil after hydrotreating. The analysis is shown for the Paroho process using western shale. Note that the sulfur in the shale is carried out with the recovered oils as is the nitrogen. Note also the carbon-hydrogen ratio of about seven to one.

The high nitrogen and oxygen content and the high viscosity of the resulting crude all cause problems. Nitrogen is a problem because few refineries built in the U.S. in the last thirty years were equipped to deal with high nitrogen bearing crudes. The nitrogen content must be reduced to a more normal level such as that for typical petroleum crude from Texas.

Nitrogen is a potential poison for many catalysts used in refining processes. Also high nitrogen fuels produce excessive NOx quantities upon combustion. Some California crudes contain oxygen levels as high or greater than that shown, therefore, the oxygen level can be handled without great difficulty.

In addition to the problem with the nitrogen and oxygen, the viscosity of the resulting oils is such that unless that oil is held at a high temperature, it is difficult to move.

FIGURE H-2-1

Pyrolysis and Oil Recovery Unit
Tosco II Process

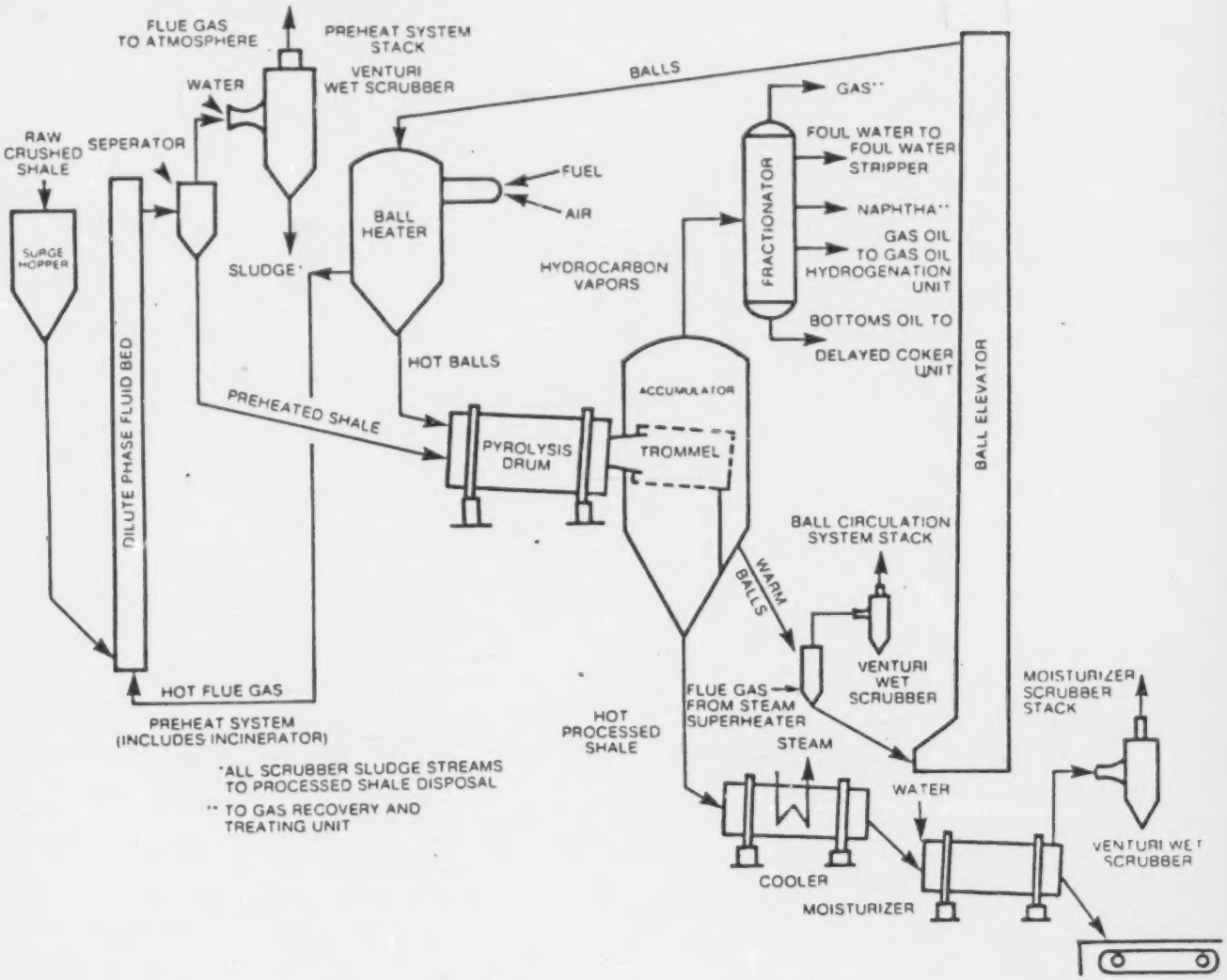

TABLE H-2-1

PROPERTIES OF WHOLE SHALE OILS AND SYNTHETIC CRUDE FROM HYDROTREATING MODULE REFINING OF PARAHO SHALE OIL

PROPERTIES OF SYNTHETIC CRUDE FROM HYDROTREATING MODULE REFINING OF PARAHO SHALE OIL	
Gravity, °API	35.8
Aniline Point, F	175
ASTM D 1160 Distillation, F	
St/5	300/360
10/30	400/500
50	600
70/90	750/900
95/EP	950/1050
Parts per Million	
Sulfur	75
Nitrogen	1000
Oxygen	170
Pour Point, F	100
Ramsbottoms Carbon, %	0.10
Viscosity at 122 F, cST	10
Viscosity at 210 F, cST	3

PROPERTIES OF WHOLE SHALE OILS	
Gravity, °API	20.2
Sulfur, Wt %	0.66
Nitrogen, Wt %	2.18
Oxygen, Wt %	1.16
Pour Point, °F	90
Ramsbottom Carbon, %	1.85
Carbon, Wt %	84.30
Hydrogen, Wt %	11.29
Hydrogen/Carbon (Atom Ratio)	1.60
Molecular Weight	326
Arsenic, ppm	28
Iron, ppm	70
Nickel, ppm	2
Ash, Wt %	0.03
Sediment, Vol %	0.1
Water, Vol %	Trace
Viscosity, cST, 122 F	24.45
ASTM D 1160 Dist., F	
St/5	386/456
10/30	508/659
50	776
70/90	871/995
95/EP	/1022
% Overhead (Excl. Trap)	94
% In Trap	1
% In Flask	5

All these problems can be overcome by some preliminary form of hydrotreatment. Hydrotreating converts the sulfur to H_2S and the nitrogen to ammonia, contaminants that are relatively easy to remove from the gas.

At the same time, hydrotreating produces a syncrude that is of sufficiently low viscosity that it is more easily pumped. Thus, the oil may be removed from the production site to an existing refinery for futher processing. A typical analysis of the hydrotreated oil from the Paraho process is shown.

Many oil companies have performed pilot refining test on raw and hydrotreated shale oils. Typical of these is test work reported by Stauffer and Yanik (Gulf Service & Technology Co.). Using pilot equipment designed for petroleum based feeds, they investigated delayed coking, catalytic cracking, middle distillate hydrotreating, naphtha pretreating and reforming. Products included gasoline, kerosene, diesel oil, and furnace oil. Their conclusions were, in part, "Shale oil fractions when suitably upgraded are quite amenable to refining in conventional processes. Product yields and quality are comparable to those obtained with a good quality petroleum crude."

3. Commercialization Assessment

Several U.S. project have been moving, albeit very slowly, toward commercialization. Occidental has developed and operated eight modules of their modified in-situ retort process. Five of them are of commercial size. Currently two commercial size retorts, numbers 7 and 8, are producing oil in accordance with design projections. Since last December, more than 40,000 barrels of oil have been produced and shipped to an Oklahoma refinery. The retorts are scheduled to burn until late fall with production projected to exceed 200,000 barrels.

Union Oil is constructing a 10,000 bbl/day module of a commercial plant near Parachute, Colorado. Retort operation is schedule to begin in mid-1983.

A 1000 ton/day (about 1000 bbl/day) shale plant was erected in the Kohla Jarve Oil Shale Processing Complex in 1976. This was based on the Russian Kiviler Process which is available for licensing in the U.S.

Several other major projects aimed at commercialization have been halted or substantially slowed down. These generally appear to be due to unsatisfactory economics or the financial

status of the sponsors. No major project has actually been cancelled.

4. Oil Replacement Potential

From the point of view of end-use suitability, shale oil has the potential for replacing all petroleum requirements of the U.S. The quantity of U.S. resources is also adequate, being in the range of plus 500 billion barrels. However, it is unlikely that during the 1985 to 1990 timeframe that shale oil will make a significant contribution to crude oil replacement.

5. Costs

Shale oil production facilities include several elements:

a. Mining

b. Retorting

c. Auxiliary above ground facilities

d. Preliminary upgrading facilities for raw oil shale

e. Infrastructure necessary for resource development, and

f. Refining of shale syncrude to end products.

Excluding the infrastructure and shale syncrude refining facilities, the mid-1982 capital investment is estimated to be in the $35,000-55,000/boe/d range with a product selling price of $50 - 60/boe.

6. Constraints

In 1979 OTA analyzed constraints (6) to the commercialization of oil shale technology. These constraints remain little changed today. The principal constraints for rapid deployment during a 1985-1990 oil cutoff are:

a. Lead time

b. Capital availability

c. Water availability

d. Socio-economic impacts in resource rich areas

e. Permitting procedures, and

f. Environmental regulations.

7. References

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I. SOLAR ENERGY

Part I-1: SOLAR ENERGY IN BUILDINGS

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I-1-2 System Configuration for a Generic Photovoltaic System

1. Introduction

This Part 1 of the Appendix I contains a broad overview evaluation of solar energy utilization in residential and commercial buildings. Two distinct technologies are discussed below: solar thermal systems and photovoltaics (PV).

2. Description

a. Solar Thermal Systems

A solar heating, cooling, or hot water system converts the thermal radiation from the sun into heat which may be used directly for heating building space or potable water as shown on Figure I-1-1; or indirectly for cooling building space through supplying thermal inputs to absorption, adsorption or Rankine cycles.

Typically, in these processes, the thermal radiation from the sun is used to heat an absorber plate which is usually made of copper, steel, iron, aluminum or glass, and either painted black or treated with selective surfaces which are specially suited to absorb thermal radiation and limit the emittance of useful thermal energy.

For residential and commercial water space heating and cooling, the absorber is covered with a single or double layer of glass or transparent plastic which allows thermal radiation to reach the absorber but retards the escape of heat. The transparent cover and absorber plate are framed and the back and sides are insulated and covered to reduce heat losses.

A heat transfer medium, either liquid or air, flows over, under, or through the absorber plate and is heated. This combination of absorber, cover, and housing is called a flat-plate solar collector. If, while the energy is being collected, there is a need for heating, cooling, or hot water, the heated transfer medium is used to meet the demand. Otherwise, it is routed to a storage device for later use.

Some type of energy storage is generally used with solar heating, cooling, and hot water systems. Sensible heat storage retains the heat produced by the solar collectors in an insulated water tank or a rock storage bin. Another alternative -- change-of-state storage -- relies on the principle that when materials change from a liquid to a solid state, they give off heat. In

certain materials, such as eutectic salts, this change of state occurs at a temperature range suitable for space heating. Thus, heat from the solar system is used to melt the material and, as the storage medium returns to a solid state, heat is supplied to the load.

One factor, which limits the amount of heat that can be collected, is that much heat can be lost through the transparent cover because of convection between the absorber plate and the cover. Evacuated-tube collectors minimize this loss because a vacuum exists between the absorber and the cover, and, consequently, convection does not occur. For this reason, tube collectors average 30 to 50 percent greater daily heat collection than the best flat plate collectors, and are generally more cost-effective. Tube collectors are also more adaptable to cooling systems.

The heat supplied from solar energy collectors can be used for cooling. At present, several different methods are being explored and developed. Of these methods, absorption refrigeration is the most advanced. Other methods include vapor compression via Rankine cycle, desiccant and molecular sieve cooling via absorption, and evaporative cooling through "rock bed regeneration." Further technological development is required before solar cooling can become a commercially viable space conditioning option. Solar cooling systems may become available commercially after 1984.

The solar system may also be used in conjunction with a heat pump in its heating function. The efficiency, or coefficient of performance (COP)[1] of a heat pump is greatly dependent upon the temperature of its input working fluid. If the heat from the solar system is not sufficient in itself to warm the space, the heat may still be used to warm the working fluid of the heat pump, thereby increasing its COP.

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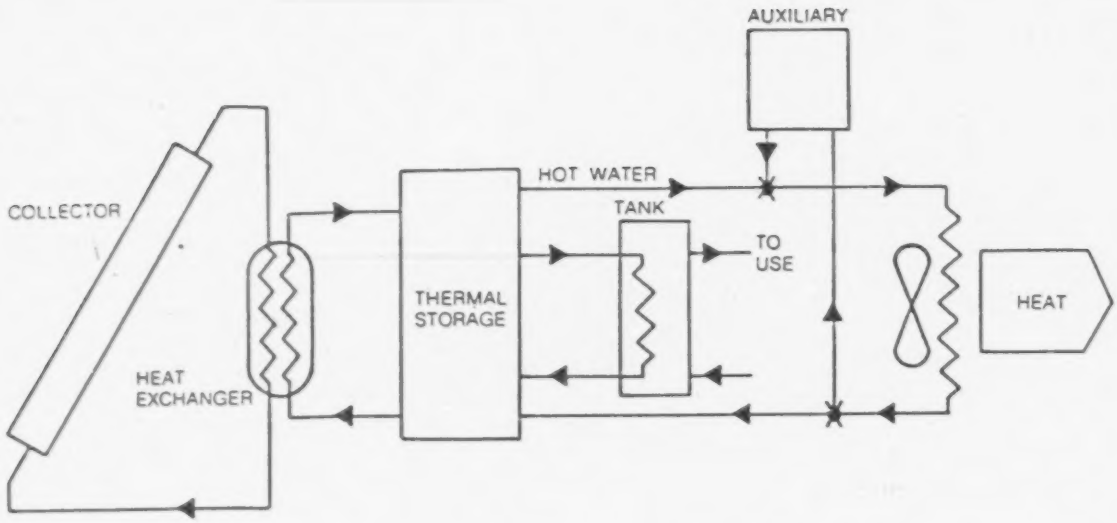
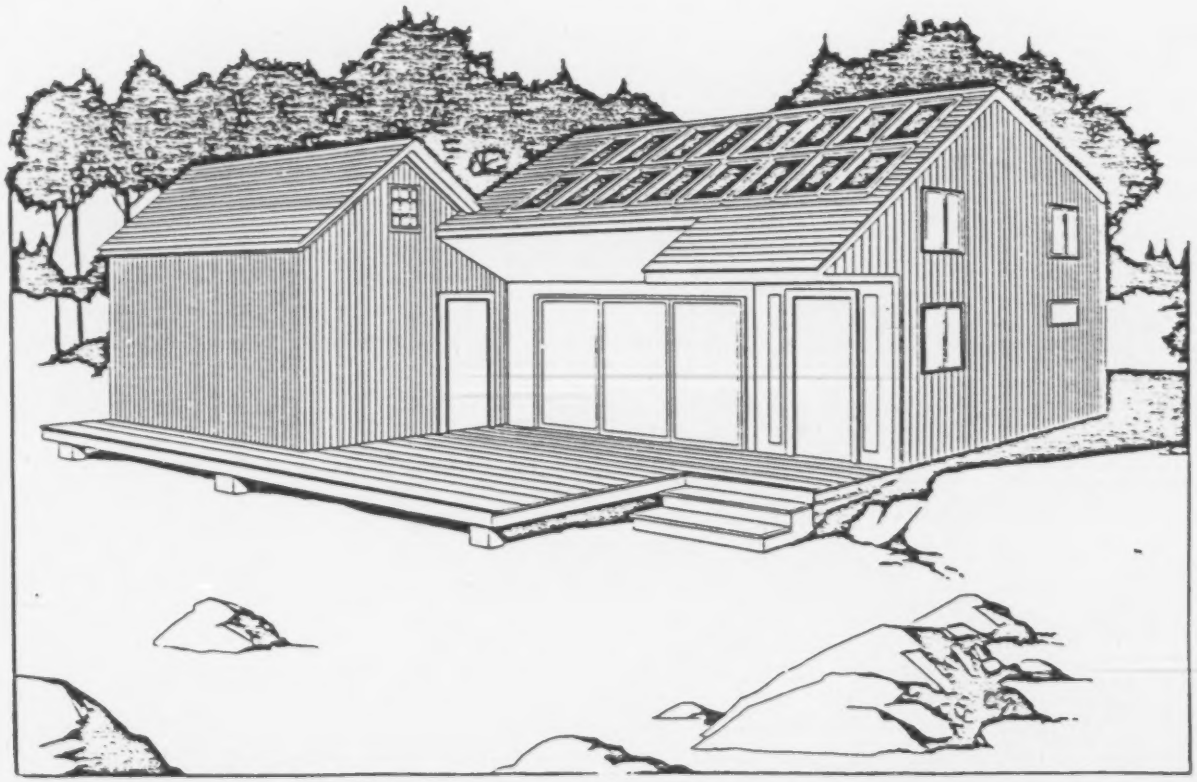
[1] COP is measured by heat supplied to the load divided by energy required to provide the heat. Example: 3 Btus of cooling supplied by a heat pump using 1 Btu of electricity yields a COP of 3.

A Potential Solar Hot Water and Space Heating System. Washington, D.C.





House: 2700 square feet. Collector area: 240 square feet. Water storage: 240 gallons. Hot water requirement: 80 gallons per day. System is 45 percent solar with 55 percent electric auxiliary backup.

FIGURE I-1-1
Source: MITRE Report M78-19

b. Photovoltaic Systems

Photovoltaic (solar cell) systems (PV's) convert solar radiation directly into direct current (dc) electricity via the photoelectric effect system configurations (see Figure I-1-2). A residential/commercial buildings system would likely consist of flat panel solar cells, a power conditioner, a small amount of buffering storage (probably utilizing batteries), a control system, and an inverter to convert dc to alternating current (ac) to match house voltage, frequency and phase.

Solar cells can now be manufactured with single-crystal silicon or amorphous silicon. Research is still being conducted to enhance electrical generation efficiency and reduce costs. Photovoltaic modules are now made almost exclusively with glass incapsulation. Plastic incapsulants pass too much moisture, which poisons the cells and corrodes the contacts.

Power conditioners and inverters are commercially available and perform well with PV systems. However, at low voltages and at small scale (less than 1 MWe), the unit cost is very high. The array conditioner is generally matched in power rating to the peak power of the array. The inverter is matched to the peak power load which is usually lower than array power.

Battery storage is expensive and inefficient. Commercially available batteries also have rather limited life expectancy with deep discharge and multiple cycling. These deficiencies make electrical storage coupled with PV quite tenuous.

Other electrical storage techniques have been proposed that are currently more complicated, inefficient, unproven, unreliable, or generally incompatible. These include flywheels, magnetic storage, advanced batteries (other than lead-acid), and compressed air. As a result, buildings applications of PV to date have been configured as fuel savers, i.e., without storage, and merely utilizing the electric grid hookup as a backup.

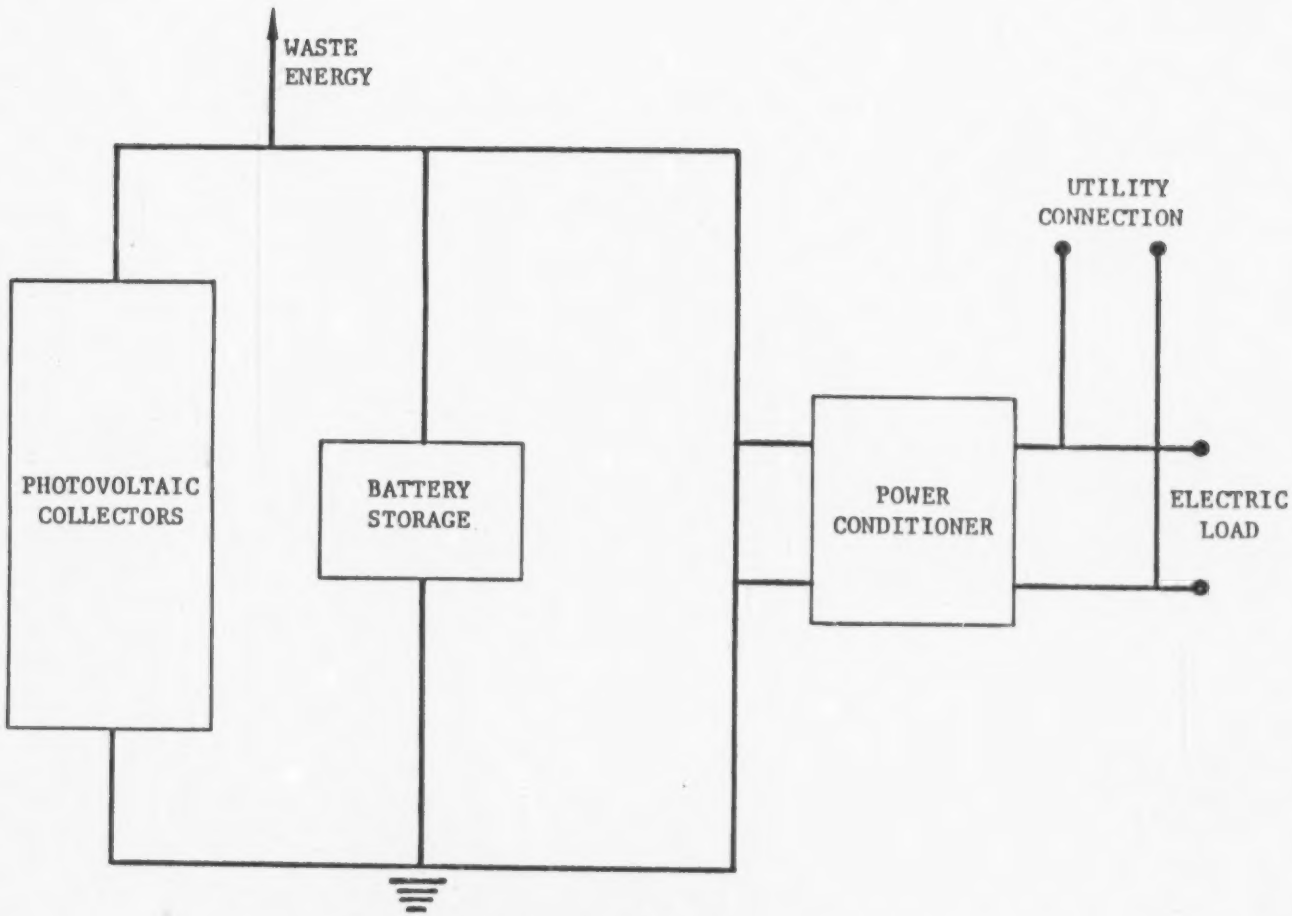


FIGURE I-1-2
SYSTEM CONFIGURATION FOR GENERIC PHOTOVOLTAIC SYSTEMS

Source: MITRE Report MTR-79W00021-03

2. Commercialization Assessment

a. Solar Thermal Systems

Commercial solar thermal systems exist for buildings applications throughout the country. Over 1,000 wholesale distributors and 100 generic suppliers of solar equipment are in business today. Annual sales approaching $1.2 billion were expected during 1982. Commercial guarantees are available from many suppliers, and some installers guarantee the installations. By 1985, sales of about 50 million square feet of active solar systems are anticipated in the U.S., at an installed cost of about $3 billion. Accelerated commercialization, without an oil cutoff, is possible, but is unlikely to provide substantial energy capacity. By 1985, about 15,000 boe/d will be displaced by residential/commercial solar thermal systems. By 1990, capacity may increase to 75,000 boe/d via the installation of about 4 million active solar heating/hot water systems.

With regard to demonstrated operability and reliability, active solar thermal systems for buildings generally perform well. Primarily in cases of poor quality control in manufacturing, untrained installers, and selection of incompatible components and materials there have been major equipment failures. Maturity in quality/performance standards in the industry have eliminated these occurrences. There are few, if any, bottlenecks to broader production in this industry. No complex skills are needed in the labor mix. Over 10,000 installers are now trained. Production capacity could be increased within 12 months to the 200 million square foot annual production level.

Materials limitations are minor. As outlined in Section IV.B the constraint imposed by strategic materials on implementation of solar thermal systems in the residential/commercial sector is rated "low" based on the use level of strategic materials. Insulation and glass industry capacity would not be constrained until solar production exceeds one billion square feet of annual installations based on Commerce Department statistics. The glass industry, for instance, produces 5 billion square feet annually.

b. Photovoltaic Systems

Commercial scale designs for small PV systems are available from 600 W to 300 kW. The technology for flat plate PV modules is developed for single crystal silicon. No commercial guarantees are being provided for systems, although components are guaranteed by some manufacturers. Accelerated commercialization is possible from the production viewpoint, although demand is not likely to increase dramatically under the current oil supply situation.

PV systems have excellent projected operability and reliability. The systems have virtually no moving parts, except for manual and automatic switches. Cell degradation had been a problem in the past, when plastic incapsulation was utilized. Maintenance usually involves washing and inspection. Lightning damage is the primary cause of catastrophic failure. A single lightning strike will destroy an entire array. Research on lightning protection is necessary to ameliorate this problem.

The technology for sales, distribution and installation is simpler than for solar thermal systems. However, production technology is lacking to produce low-cost, high-efficiency PV cells. With modest investment, on the order of $15 million, however, cell production could be increased from 5 MWe (peak) per year to 100 MWe within 18 months. This is based on an estimated [13] $25 million capital cost required to construct a plant producing 20×10^6 ft^2 of PV cells per year with 10 We (peak) generated per ft^2 (200 MWe peak).

There are few materials constraints for commercial PV systems based on silicon. Advanced cells using gallium, arsenic and cadmium may cause problems, but these cell types are not commercial. Lead-acid batteries could cause bottlenecks if production of PV systems become widespread using electrical storage, but this event is unlikely.

3. Oil Replacement Potential

a. Solar Thermal Systems

There are no resource limitations to expansion of the solar thermal buildings industry to supply up to one billion square feet of collector systems per year, other than cost. Manpower, materials, and technology are available; price is the inhibiting factor.

In the rapid deployment scenario during an oil crisis, when the price of oil and natural gas will increase dramatically, commercialization of solar thermal buildings systems will be accelerated. Energy costs may cause the equipment to rise in price by about 20 percent, but the cost-effectiveness may improve by over a factor of two during the crisis. This event will make solar thermal systems competitive against oil and gas usage in homes and commercial buildings in virtually every part of the country.

The current installed capacity of solar thermal buildings systems displaces 3,000 boe/d. By 1985, capacity should reach 15,000 boe/d. Average collector performance is 200,000 Btu/ft^2/year, displacing about 300,000 Btu/ft^2/year in oil and gas. Achievement of 200,000 boe/d by 1990 would involve installation of about 1.34 billion square feet of collector systems, worth over $60 billion. About 10 million systems would be required to achieve this goal, with a peak installation rate (in 1990) of about 2 million systems. This level of deployment is not feasible. A 75,000 boe/day level (five-fold increase) by 1990 is more realistic and possible without resource, manufacturing, labor or technology constraints. Current lead time (order to installation) averages less than a month. In an accelerated case, lead times could be expected to lengthen to the 2 to 3 month level, but this would be due more to conventional equipment delivery delays (storage tanks, pumps, piping, etc.)

The best regions for solar thermal systems will have an average fuel displacement performance of 500,000 to 700,000 Btu/ft^2/yr. The regions and their respective portions that can achieve this performance level are shown below along with the maximum residentially consumed oil and kerosene that can be displaced in each region (Standard Federal regions 1, 2, 3, and 5 cannot achieve 500,000 to 700,000 Btu/ft^2/yr performance):

Standard Federal Region	Portion achieving average 600,000-800,000 Btu/ft²/yr Oil Displacement (%)	1985 Projected Oil and Kerosene for Heat/Hot Water (Mbbl/d)	Maximum Oil and Kerosene Displaced (Mbbl/d)
4	30	83	24.9
6	100	58	58.0
7	30	34	10.2
8	100	16	16.0
9	100	14	14.0
10	20	25	5.0
Totals		230	128.1

For estimating the maximum displacement of natural gas by solar thermal in the residential sector a similar analysis can be performed. Use of natural gas, distillate and kerosene has been tabulated by number of households according to U.S. Census Region. The regions and their respective portions that can achieve 600,000-800,000 Btu/ft²/yr fuel displacement are shown below along with the number of corresponding households:

	Total Households (MM)		Achieve 600,000-800,000 Btu/ft²/yr Fuel Displacement		
Census Region	Natural Gas (NG)	Oil/ Kerosene (O/K)	Portion (%)	Household (MM) NG	O/K
West	11.1	0.5	95	10.5	0.5
South	11.8	3.1	70	8.3	2.2
North Central	15.0	1.5	20	3.0	0.3
Northeast	6.6	8.2	0	0	0
Total	44.5	13.3		21.8	3.0

Actual solar installations would be less than the number of households owing to multiple dwelling structures but nevertheless the potential natural gas displacement remains approximately 7 times that of oil/kerosene.

It is not anticipated that in the 1985-1990 time frame after an oil disruption that significant natural gas displacement by solar thermal can occur. Economic incentives will favor displacement of oil rather than natural gas since oil may be as high as 200 $/bbl with natural gas at 55 $/boe (see Appendix 0). The manufacturing facilities will be hard pressed to meet a 75,000 boe/d level of solar thermal hardware (a

five-fold increase over the 1985 projected level) by 1990 and additional components to replace significant amounts of natural gas will not be available.

b. Photovoltaics Systems

PV systems are not limited by resource constraints. In the event of a major oil cutoff, accelerated PV commercialization is likely.

Current PV cell module production is less than 5 MWe (peak) per year. By 1985, production may reach 20 MWe (peak) per year for all PV applications. However, the buildings sector may never achieve market penetration (except for remote locations) by 1985. Current installations number less than 100 worldwide in buildings, averaging 600 W (peak).

If a cost-effective PV buildings concept could be developed, production capacity could achieve 1,000 MWe (peak) per year in less than 2 years. This is based on the lead time for electro-mechanical, optical- and chemical-type equipment of 12 to 18 months and the capacity to manufacture this equipment (much of which is manufactured in Europe)[13]. Installing 10 million 1 kWe (peak) units by 1990 is physically possible. Annual electrical delivery would be about 1,200 kWh(e)/kWe (peak), yielding 75,000 boe/d for 10 GWe (peak) capacity throughout the country. Such system capacity would likely cost consumers over $60 billion, and displace electricity worth only $2 billion per year. Unless system costs reduce to $3 per peak watt (vs. $10 for cells alone today), major market penetration is unlikely.

4. Costs

a. Solar Thermal Systems

Current costs for solar thermal systems range from $40 to $100 per installed square foot. Displacement of oil ranges from 150,000 Btu/ft^2/yr to 1,500,000 Btu/ft^2/yr, depending on location and displaced energy source (oil/gas/electricity). An average value for the nation would be $50 per square/foot displacing 300,000 Btu/ft^2/yr, or $916/boe/yr. At a 20 percent fixed charge rate (appropriate for this sector), equivalent cost is $183/bbl. In high level production, it is anticipated that national average system cost may reduce, but energy intensiveness may cause cost increases that offset production scale cost decreases.

A shift of American population to the Sun Belt may offer a greater opportunity for solar systems, in that average collector performance would be in the higher range. If 2/3 of collector sales occur in the Southwest, national average cost for solar thermal systems for buildings would likely be less than $100/boe. In the best regions for solar thermal, where oil displacement performance averages 500,000 to 700,000 Btu/ft^2/yr, the annual cost is $80 to 110/boe. This cost would be competitive in the event of an oil cutoff.

b. Photovoltaic System

Current costs for PV buildings systems range from $10 to $40 per peak watt. Displacement of oil ranges from 0.0017 to 0.0040 bbl/W(p)/yr. A national average value, assuming all PV systems were installed in the Southwest, would be $2,500/boe/yr. The resulting displaced oil price would be roughly $500/bbl. Unless system costs reduce to the $3 per peak watt range ($150/boe), market penetration is highly unlikely.

5. Non-institutional Constraints

a. Solar Thermal Systems

Labor availability, skill mix and manpower base are sufficient to meet anticipated growth needs in this industry. Materials and manufacturing needs are also adequate, and are primarily domestic. Expansion to the one billion square foot annual rate of domestic production under crisis scenario is feasible and unconstrained. There are no inherent transportation sector impacts, as the technology is highly distributed. There are few land or physical space constraints, other than existing building orientation (a southern exposure is desirable). The restriction on market expansion primarily is due to capital constraints.

To meet the 200,000 boe/d goal by 1990, nearly $60 billion in capital would be expended by homeowners and building landlords in the nation. Given the choice of $150 to $250 per barrel oil in an oil cutoff the solar alternative will be attractive, even at annual interest rates of 25 percent. Many homeowners would likely build their own solar systems rather than pay $2,500 per season for heating and hot water. An average 200 ft^2 installation would cost $4,000 wholesale, and save $2,000 per year in oil costs at $150/bbl. There will remain 40 to 60 million housing units where residents would be unable to install solar thermal systems due to

cost, institutional or physical space/orientation limitations. This is based on a G&H analysis of suitability of housing units for solar thermal technology, i.e., How big is the market? Of the 81.6 million households in the U.S. nearly thirty percent are multidwelling or attached in a physical manner that precludes sufficient area for collectors. There are also institutional problems in this thirty percent such as ownership of the installation. Of the remaining single family detached and mobile homes (57.6 million households) approximately twenty-five percent are constrained by physical limitations such as shadows and poor collector performance. Of the balance (43.2 million) it is estimated that up to 50 percent may not be able to afford the solar system.

b. Photovoltaic Systems

Manpower, materials, and manufacturing capacity factors will not limit PV systems for buildings. The cost factor will be a major constraints however.

To meet the 200,000 boe/d goal by 1990, roughly $200 billion would be expended for PV buildings units. Given that electricity prices would likely remain less than 20¢/kWhe in the oil cutoff scenario ($92/boe), PV systems would be forced to reduce in price to less than $3 per peak watt to be competitive. Reflecting today's known technology and manufacturing techniques, such price reduction is highly unlikely.

6. Institutional and Regulatory Constraints

a. Solar Thermal Systems

There are few, if any, major institutional or regulatory contraints to solar thermal systems for buildings. Local building codes and standards cause localized minor disruptions to installers; e.g., requiring double-walled heat exchangers for domestic hot water, requiring glycerin to be used rather than glycol, requiring fire protection devices, etc. Local covenants in some communities also cause problems, such as requiring solar units to not be visible from the street.

Tax policy has had a dramatic impact on this industry. The current 40 percent tax credit for residential buildings solar applications has greatly stimulated sales, especially in California (where the state adds 15 percent). Proponents in the industry believe that the federal tax credit should be extended, which is

likely in the event of an oil cutoff. If the current tax credit is allowed to expire in 1985, the industry would be affected adversely to a major extent. If an oil cutoff occured two years later, there would be no local infrastructure in place to realize the market potential. One suggested policy for OTA to consider is the extension of the current credits to 1990.

b. Photovoltaic Systems

What is stated for solar thermal systems in buildings is basically true for PV systems for buildings. However, PV systems require extensive R&D to reduce prices to the affordable range. Current technology is simply insufficient to project market viability. Recent DOE budget cuts for PV R&D of over 60 percent are likely to retard the technology development even further.

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I. SOLAR ENERGY

PART I-2: SOLAR ENERGY UTILIZATION IN INDUSTRY

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I-2-1 A Potential Solar Powers Heat System: A Metal Finishing Plant, Riverside, California

1. Description

Solar thermal systems have broad applications throughout industry. However, photovoltaic systems are not anticipated to be cost-effective in the time frame of this analysis (to 1990) in the industrial sector, and therefore are eliminated from further consideration.

Some of the most likely solar process heat applications include crop and lumber drying, canning, textiles, cement block curing, washing operations, uranium milling, greenhouses, animal/poultry shelters, forage drying, plastic curing, and metal finishing.

These systems are similar to those used for residential and commercial buildings in that collectors capture the thermal energy from the sun and this heat is transferred in a working fluid to storage or directly to the process. Depending upon the application and the temperature required, different types of collectors are used. A typical parabolic collector is shown in Figure I-2-1.

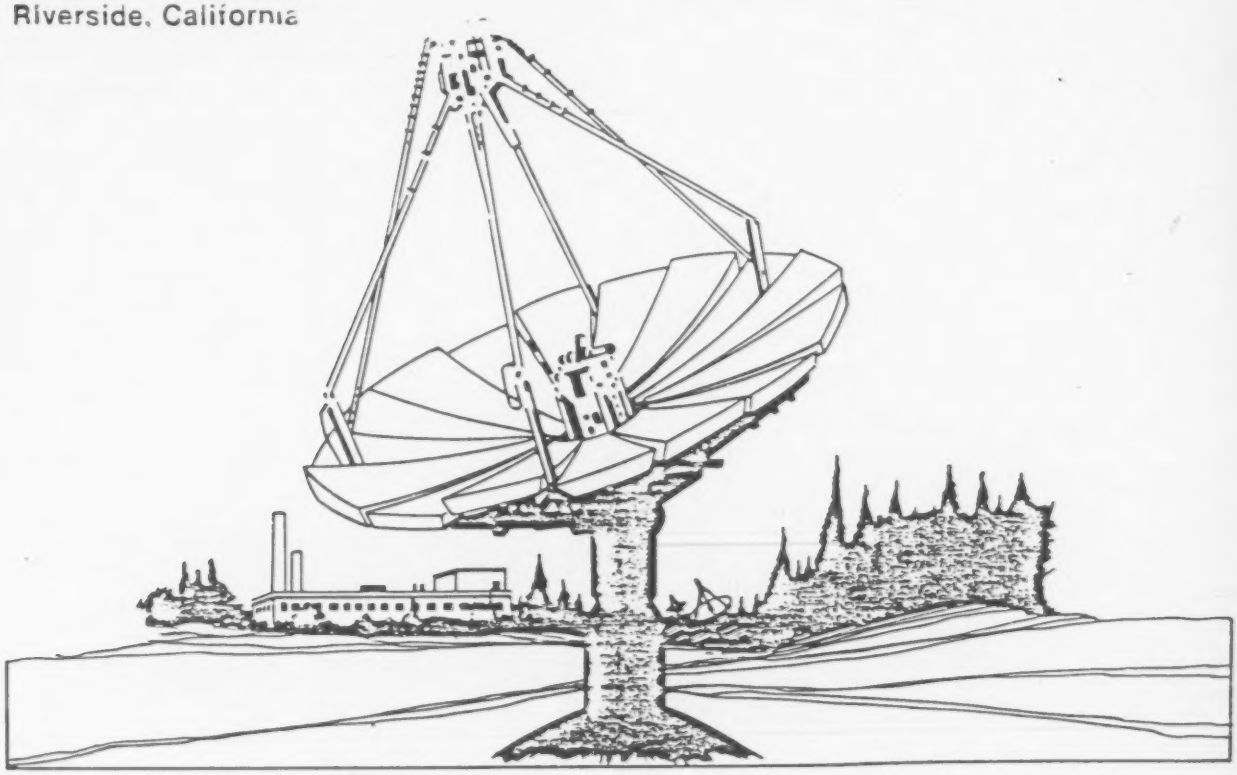
Six demonstration systems under DOE sponsorship are currently in operation. The systems average 10,000 square feet of collector area. Thirty commercial systems are currently in operation.

Commercial sales of high performance collectors have increased at a rate of 300 percent per year for the past four years and this increase is expected to continue.

Lower temperature collectors include solar ponds consisting of a water-filled plastic bag with a clear top and black bottom, plastic flat-plate collectors of the type used to heat swimming pools, and metal flat-plate and evacuated-tube collectors such as those used for heating and cooling of buildings.

Higher temperature applications require collectors that concentrate the energy from the sun. These include parabolic concentrators, segmented mirrors and parabolic dishes. These collectors are sometimes designed to track the sun as it moves across the sky, thus achieving high temperatures for longer periods during the day. Thermal storage for low temperature applications is usually water or rock. For higher temperatures a combination of oil and rock, pressurized water or salt can be used. The majority of the process heat applications require high temperatures and thus would need tracking concentrators.

A Potential Solar Process Heat System:
A Metal Finishing Plant.
Riverside, California



(Based on design concept marketed by Omnium G of Anaheim, California)

Six acres of land. 120 parabolic dish dual-axis tracking collectors (diameter of each: 22 feet). Total aperture area of collectors: 45,700 square feet. Thermal storage: 12 hours. System is 70 percent solar and 30 percent oil auxiliary. System operates 12 hours per day, 7 days per week and requires 8000 pounds of steam per hour of 400°F and 400 pounds per square inch pressure. Yearly solar output 22,400 MMBtu steam.

FIGURE I-2-1

Source: MITRE Report M78-19

Large scale industrial systems may be based upon the central receiver concept, which is discussed as part of the electric utility applications (Appendix I-3). These systems are compatible with ore smelting, mineral reduction, enhanced oil recovery, oil refining, chemical processes, food processing and water desalination.

2. Commercialization Assessment

Commercial scale designs exist for a broad range of industrial applications using solar thermal equipment. Technology is available and being offered with commercial guarantees of up to five years on hardware. Commercialization can be accelerated to provide substantial oil savings, perhaps as much as to 0.4 MM boe/d by 1990, by using this technology.

There are substantial similarities and contrasts between solar thermal technology for industry and for buildings. A cost advantage for the industrial process heat systems is expected due to:

a. Economy of scale for the larger industrial purchases (about 20 percent reduction over building systems).

b. Reduced plumbing and installation labor requirements (about 15 percent reduction).

c. The use of existing O&M personnel for on-site maintenance.

d. Lower shipping costs per unit area (about 5 percent reduction).

e. Reduced profit margins for manufacturers and installers due to competitive bidding and direct purchasing (about 35 percent reduction).

f. Higher efficiency of collection of sunlight due to open-loop in most process heat operations.

g. Better load matching coupled with year-round use.

h. Greater insolation available due to tracking.

i. Better tax treatment via depreciation allowances and existing tax credits coupled with higher tax rates.

These conditions lead to ultimate systems costs of from $10 to $25 per square foot for industrial systems vs. $40 to $100 per square foot of collector area for residential/commercial,

with 50 percent to 100 percent more energy per unit area delivered to the load for industrial over residential/commercial. A comparison of residental, commercial and industrial systems is shown in Table I-2-1.

a. Similarities

For applications in the range of 40 C-100 C (104 F-212 F), both sectors may employ flat plate or evacuated tubular collectors with water or rock storage.

Both sectors require some type of storage and/or conventional backup or auxiliary to provide reliable service.

Generally, sufficient sunlight is available on roofs and grounds to satisfy a significant fraction of the energy demands of each facility.

In most cases, retrofit installations into existing structures are more difficult and can be more costly than new installations.

b. Differences

There are about 70 million residential housing units in the U.S. and about 3 million commercial units versus about 0.4 million industrial installations.

Industrial installations are generally much larger than building installations.

Building applications tend to be seasonal (3 to 6 months per year), while industry process heat demand tends to be year-round.

Module sizes for industrial solar equipment should be much larger than for buildings, using less plumbing and installation labor per unit area.

Tracking systems would most likely be used for industrial applications, enabling more insolation to be utilized.

Parking lot and ground areas would most likely be used for industrial applications reducing retrofit structural support problems and reducing the requirement to acquire more land.

Small business and mechanical contractors would most likely be used for buildings installations; while large architecture/engineering firms and general contractors would likely competitively bid for industrial applications, resulting in lower profit margins for installation.

Large-scale industrial purchases will generally lead to price breaks in equipment costs, economy of scale, and lower shipping costs.

Closed-loop buildings systems will most likely operate close to the delivery temperature while open-loop industrial systems would have average collector temperatures much lower than the delivery temperature, leading to higher average collection efficiency.

Operations and maintenance personnel would generally be available for industrial systems on-site while O&M labor would have to be on call for residential/commercial systems.

Industrial/commercial solar equipment can be depreciated and is eligible for tax credits, while residential equipment is eligible only for the tax credit.

Existing solar IPH systems have been quite reliable and have operated as designed. The systems are simple to operate and maintain.

The technology for high-temperature systems does utilize some high-grade alloys for receiver tubes. However, materials contraints would not be limiting unless production exceeds one billion square feet annually, and only then for glass and some high-temperature alloys, such as Inconel 617. Substitutes for Inconel 617, such as Incoloy 800 and 825, have lower but adequate high temperature stress rupture properties and do not contain cobalt.

3. Oil Replacement Potential

The oil replacement potential for solar thermal industrial systems is large, more than 200,000 boe/d by 1990. There are few resource limitations. Industrial expansion in the Sun Belt also favors the use of solar thermal systems.

In the oil supply disruption scenario, industry will likely shift from oil to natural gas where feasible. Natural gas prices should climb to well above $10/MMBtu, as demand increases in all sectors. In such cases, the

cost-effectiveness of solar thermal industrial systems will be enhanced, which should promote rapid market penetration.

Current solar thermal industrial capacity is equivalent to only 1000 boe/d. By 1985, it is anticipated that capacity will increase to about 5000 to 10,000 boe/d. A major industrial facility (37,000,000 ft^2) is planned for operation by 1987 in California, that alone would displace 14,000 boe/d. If 20 such systems could be built by 1990, along with 200 other smaller units (in the one to three million ft^2 range of size), capacity of 400,000 boe/d could be achieved.

Production capacity is planned to expand to 30,000,000 ft^2/yr by 1985. The lead time for this expansion is about two years. At the current tripling rate in expanded sales, one billion ft^2 annual capacity would be reached during the 1988-89 time frame.

4. Costs

The current product cost of energy from solar thermal industrial systems is about $80/boe. Expected price reductions by 1985 may result in product costs in the $30 to $50 per barrel oil equivalent range (1982 dollars). The total capital cost varies from 70,000 to 200,000 dollars per barrel per day. Energy intensiveness in the manufacturing of some solar system components may increase these costs by about 20 percent in the event of an oil cutoff, however. In any case, solar thermal systems will be cost-competitive with natural gas at or above $10/MMBtu in this timeframe. As a result, major market penetration under oil cut-off scenario could be anticipated.

5. Non-institutional Constraints

Labor availability and skills required for solar thermal industrial systems are not considered limiting factors. Materials and manufacturing facilities can easily accommodate major expansion of the solar industry. Most current capacity is domestic, although Germany, France, and Japan expect to develop capacity for this technology in the same time frame. Domestic capacity should be sufficient to handle U.S. needs. Transportation of materials and feedstocks is not expected to be a problem.

TABLE I-2-1

SOLAR HEATING:

A COMPARISON OF BUILDINGS SYSTEMS
AND PROCESS HEAT SYSTEMS

SYSTEM TYPE	COLLECTOR AREA AVERAGE (Ft^2)	ENERGY DELIVERED (MMBtu/Yr/Ft^2)	EFFECTIVE GROUND AREA FOR TYPICAL SYSTEMS
RESIDENTIAL			
Hot Water (HW)	50-100	0.10-0.30	50-100 FT^2
Heating (H)+HW	100-1000	0.06-0.28	100-1000 FT^2
Cooling (C) + H + HW	300-1000	0.08-0.29	300-1000 FT^2
COMMERCIAL			
HW	100-4000	0.10-0.30	100-8000 FT^2
H + HW	1000-30,000	0.06-0.28	1000-60,000 FT^2
C + H + HW	1000-30,000	0.08-0.29	1000-60,000 FT^2
INDUSTRIAL			
Low Temp (<100 C)	30,000-3,000,000	0.12-0.36	16.4-48.0 Acres(1)
Mid Temp (100-150 C)	30,000-3,000,000	0.19-0.32	36.0-60.0 Acres
High Temp (150-800 C)	30,000-3,000,000	0.18-0.54	21.0-64.0 Acres

(1) Based on an effective system output of 10^{11} Btu/Year average.

Land requirements are a problem for existing industrial facilities. However, the shift of industry to the Sun Belt will free the potential user to select a site with suitable land and space.

Capital availability will be a problem. To achieve 200,000 boe/d capacity, nearly $20 billion would be expended. With a three-year payback criterion, equivalent oil price of $90/bbl ($16.60/MMBtu) must be exceeded for the displaced fuel. Since oil is anticipated to be in this range or higher, the solar industrial systems should be competitive. Natural gas price is anticipated at $55/boe (See Appendix 0) thus making installations at oil burning facilities more attractive. Interest rates of over 25 percent could be tolerated in this sector to implement the use of this technology.

6. Institutional and Regulatory Constraints

Regulatory issues are considered relatively benign for solar industrial systems. Environmental effects are actually beneficial on balance. Reduced emissions, greater domestic employment, and increased production efficiency accompany solar installation. Land use impacts are somewhat limiting, and siting constraints are possible for larger installations.

Construction time for solar installations in this sector range from one to three years. Lead times for design and permitting add one to two years to the procurement cycle. Since industry usually plans for three to five year horizons, this time span is compatible for widespread implementation by 1990.

Solar industrial systems currently are encouraged by a 25 percent federal investment tax credit through 1985, which may be extended under new legislation before Congress. A five-year, 87.5 percent tax depreciation schedule is also available under current law. Given the enormous potential for this technology and application, it would be advisable for OTA to support continued favored tax treatment to solar thermal industrial systems.

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I. SOLAR ENERGY

Part I-3 : SOLAR THERMAL ELECTRIC UTILITY SYSTEMS

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I-3-1 A Potential Solar Thermal Electric Utility System Fuel Saver Near Yuma, Arizona

1. Description

A principal solar thermal system for electric utilities is the central receiver concept in which sunlight, falling upon a large field of mirrors (heliostats) will be focused on a receiver located on top of a high tower in the middle of the mirror field as shown in Figure I-3-1. The mirrors are continuously aimed by tracking mechanisms. Heat collected in the receiver is transferred to a working fluid which is used to run a turbogenerator. The receivers may use air, water/steam, molten salt or liquid metal as the heat transfer fluid.

Solar thermal electric power plants will likely be located in the arid southwestern U.S. and can be configured with a thermal storage system, with a combustion turbine backup or as a fuel saver without storage or backup. Solar thermal fuel savers located in the southwestern deserts may have a natural match between the utility peak and intermediate loads and sunlight hours.

Combined with the high frequency of sunny days, this would reduce the conventional backup requirements.

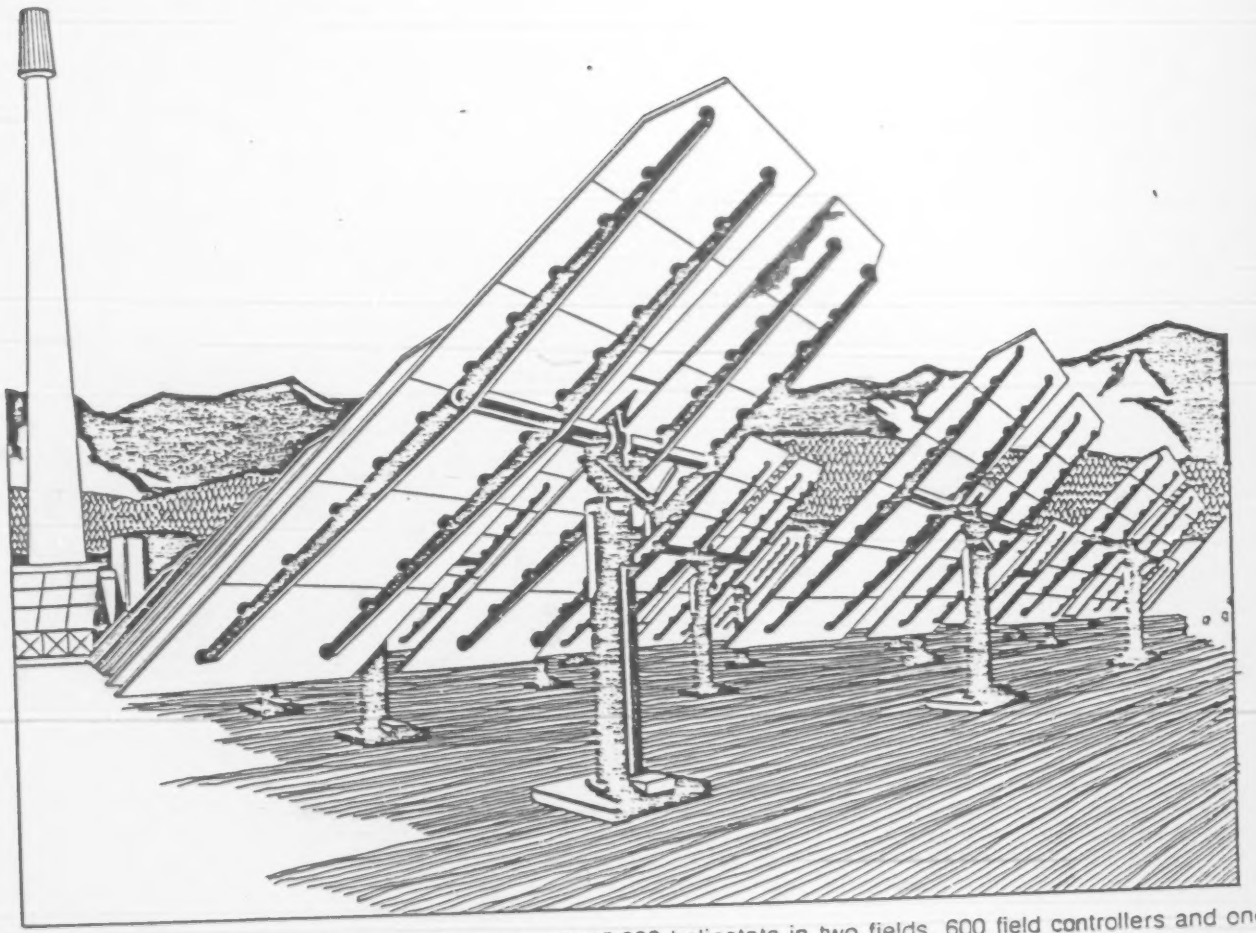
A 10 MWe demonstration plant began operation in Barstow, California in 1981. The first commercial systems are expected to begin operation in 1986.[1]

2. Commercialization Assessment

Commercial-scale conceptual and preliminary designs exist for solar thermal control receiver systems up to 560 MWe. Most were funded under DOE contracts in the Solar Thermal or Central Receiver Divisions. Nearly $500 million has been spent on central receiver RD&D, including $140 million for the Barstow pilot plant. The next step to commercialization was to have been the demonstration of a 100 MWe scale facility under DOE sponsorship, but that idea was dropped in the current budget. An 80 percent cutback in central receiver R&D has resulted since 1980 in DOE's budget. Similarly, EPRI's budget has been severely cut.

[1] Recent studies by DOE looked into the possibility of "repowering" existing fossil facility with solar thermal in order to save fuel. The solar and fossil boilers would both use the same turbogenerator, electric switchyard, and condenser. These systems, may become commercially available by 1986.

A Potential Solar Thermal Electric Utility System: Fuel Saver Near Yuma, Arizona



Land site: 670 acres (2.7 million square meters). 15,000 heliostats in two fields, 600 field controllers and one master computer. Two reinforced concrete towers, each 750 feet high with a 2000 square foot aperture cavity receiver. Reflection area for each heliostat: 400 square feet. Operational life: 30 years. Availability during sunshine hours when sun is 10 degrees over horizon: 90 percent. Rated capacity: 100 MWe. Capacity factor 37 percent. Annual output: 320 million kilowatt hours.

FIGURE I-3-1

Source: MITRE Report M78-19

Despite these cuts, industry is continuing to work with the central receiver concept. Several industrial consortium are working with utilities to develop plans for third-party, PURPA-qualified facilities at scales ranging from 10 to 560 MWe. If their plans succeed, nearly $100 million will be spent over the next 2 years for commercial development. The earliest utility-owned, commercial, solar thermal electric power plants may not be built before 1990, unless interest rates decline to levels below utility-regulated rates of return.

Commercialization could be vastly accelerated for central receivers in utility applications. "Power towers" could be built and operational by 1986 in California, Arizona, New Mexico, Texas, Nevada and Utah if proper incentives were in place for utilities.

The Central Receiver Test Facility (CRTF) and Solar One (the Barstow pilot plant) are the only operational power towers in the U.S. ARCO has a small, 1 MW unit near Bakersfield, CA, that is undergoing testing for enhanced oil recovery (not power generation). Operations and maintenance experience has been quite limited, but encouraging. The technology has undergone proof of technical and engineering concept, but is not economic at commercial scale. Commercial scale proof-of-concept will not be known until the first 50 to 100 MWe modules are operational. Solar One operation is hampered by a cutback in funding support that precluded the installation of its master control subsystem. The plant has been operated without its storage subsystem as a result. Integrated operation has not been possible because of lack of automated control.

In the area of materials constraints, production rates in excess of heliostats of one billion ft^2 per year might cause bottlenecks in glass and superalloy supplier industries. Otherwise, fabricated units (such as heliostats) currently have a two year lead time.

3. Oil Replacement Potential

There is virtually no potential for oil replacement by solar thermal electric technology, owned by utilities, before 1990. However, industrial-owned electric generation stations may be built up to 10,000 MWe capacity in this time frame.

These are no real or apparent resource constraints to limit this potential.

In the oil cut-off scenario, increased oil and gas prices will favor this technology's market penetration. Solar

thermal is one of the few alternatives to oil and natural gas for daytime power generation in Sun Belt utility grids.

In terms of production capacity, current installed oil equivalent displacement is 200 bbl/day. By 1985, this level may increase to 2600 bbl/day if Southern California Edison and Pacific Gas & Electric build their 100 MW and 30 MW systems as planned. If the industrial consortium are successful in financing their system, by 1987 capacity would increase to 30,000 bbl/day, and up to 200,000 bbl/day by 1990. Annual production capacity of over 50,000 heliostats per year may be reached in 1985 to support the first commercial units. By 1987 capacity could reach 250,000 units per year, representing an incremental increase of 50,000 boe/day/year.

4. Costs

Projected product cost for central receiver systems is in the range of 8¢ to 12¢ per kWhe (1982 dollars), or $37/boe to $55/boe. This is equivalent to natural gas at $8 to $12 per MMBtu, the expected price range in the 1985-1990 time frame. In the event of a major oil cut-off, prices may increase by about 10 to 20 percent, which should not have a dramatic market effect. The total capital cost for solar thermal facilities by 1990 is $70,000 to $100,000/bbl/day.

5. Non-institutional Constraints

Labor and manufacturing skill requirements for central receivers are not considered limiting. The manpower pool is more than adequate. Materials will not be limiting unless production levels exceed one billion ft^2/yr. When capacity reaches the 250,000 heliostats annual level to support the oil replacement of 200,000 boe/d by 1990, the production level would reach 150 million ft^2/yr. These facilities are likely to be domestic, with Japanese, French and German competition.

Transportation of hardware to construction sites may require local expansion, which would be integrated with construction schedules. Construction lead times of three to five years (including design and permitting) are anticipated.

Land use may cause some siting difficulties. Water use by the air-cooled (gas turbine) systems is minimal, but steam-type systems consume large quantities of water for cooling towers, which may cause local problems. Other problems relate to transmission of electricity from desert sites to load centers, which can cause delays. Lead times of

three to seven years can result from transmission line routing and permitting constraints.

The most severe constraint is the availability of capital. If interest rates soar during a cutoff, utilities will be unable to raise financing at their low regulated rate of return (as has been the case for the last three years). Industrial PURPA facilities would require as much as 20¢/kWhe to finance central receiver ventures. However, if the utilities have no other choice but to purchase power, rather than build new capacity of any type, this price may be viable.

6. Institutional and Regulatory Constraints

Every factor discussed in Appendix I-2, Solar Energy Utilization in Industry, applies to this technology in the utility sector. However, the regulatory issues have greater impact on utilities, not only with regard to financing, but also regarding tax treatment and licensing delays. Utilities get a 15-year write-off, no incremental solar business tax credit, and must file permits and licenses with FERC for plant construction and with the PUC's for rate adjustments. The net effect is a far more burdensome process for new plant construction, and economic viability is threatened. If public utilities are to be expected to embrace this new technology, incentives must be granted by the government. These may include rate relief, reduction of regulation, allowed higher rates of return to equity, guaranteed loans, and tax relief (in some cases, utilities pay no taxes due to prior capital commitments). In a crisis situation, the utilities would be unable to respond without major changes to these conditions.

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J. WOOD IN UTILITIES AND INDUSTRIES

PART 1: WOOD AS A UTILITY FUEL

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1. Description

2. Commercialization Assessment

3. Oil Replacement Potential

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5. Non-institutional Constraints

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J-1-1 . Summary of Oil Designed Oil Burning Power Plants of 200 MW or Less Capacity

1. Description

Historically, the use of wood as a utility fuel has been quite limited. Sixteen (16) utilities have had experience with wood as a utility fuel, although only 10 utilities encompassing 11 plants now use wood in some form [1]. In several instances, wood is used in a co-firing mode with other fossil fuels (three plants use coal and one uses gas/oil). Of the 11 plants, one is between 100 and 200 MW, two are between 50 and 100 MW and the balance are less than 50 MW.

In order to use wood to displace oil in utility plants, it would be necessary to install a "slide-along" wood-fired new stoker boiler similar to that described in the discussion on wood as fuel for industry (Appendix J-3).

2. Commercialization Assessment

The design and installation of a wood burning slide-along stoker-fired boiler should not present any unusual technical problems. However, wood burning experience is limited to units of 200 MW or less capacity. Thus, for the purposes of this study, it is assumed that only units of 200 MW or less capacity would be potential candidates for conversion to wood burning using a slide-along stoker-fired boiler. It is further assumed that only oil-designed units would be potential candidates since coal-designed boilers are prime candidates for utilizing coal, either by direct coal reconversion, coal-oil-mixtures or coal-water-mixtures.

3. Oil Replacement Potential

Current use of wood as a utility fuel amounts to 750 boe/d. In order to estimate oil replacement potential, a list is compiled of the number of units and megawatt capacity of oil-designed units of 200 MW or less capacity in each state (including the District of Columbia), broken down by federal region. This information is shown in Table J-1-1. Note that while the total capacity is equal to 14,182 MWe, many of these units are probably being used for intermediate and peaking purposes and the capacity factor for these units is assumed to be 15 percent. The maximum theoretical oil replacement potential (MTORP) is estimated as follows, assuming an average plant heat rate of 9500 Btu/kWh and 15 percent capacity factor:

$$\text{MTORP} = \frac{14{,}182{,}000 \text{ kWe} \times 9500 \text{ Btu/kWh} \times 24 \text{ hr/day} \times 0.15}{5.5 \times 10^6 \text{ Btu/bbl}}$$

MTORP = 88,000 bbl/day.

In order to achieve this oil replacement potential it would be necessary that 100 percent of the MTORP be realized, that is, 100 percent of the 14,182 MWe of capacity be converted to wood burning. It is unlikely that this market penetration will be achieved considering the need to have the source of wood in close proximity to the boiler installation and technical difficulties in repowering with wood. This subject is discussed further in the subsequent sections dealing with non-institutional and institutional constraints. In summary, it is concluded that wood as a utility fuel has limited oil replacement potential in the less than 40,000 boe/d range.

4. Costs

The capital costs associated with conversion to wood burning include the costs for a slide-along stoker-fired boiler, steam piping and control systems integration, wood storage and handling system, a particulate control system and a solid waste disposal system. The capital cost of conversion is a function of a number of site specific and plant specific factors, including unit size, fuel characteristics and various site characteristics. The capital cost based on Gibbs & Hill in-house cost data is estimated to be in the range of $300 to $450 per kW or $21,000 to 31,000 boe/d.

The cost of conversion in dollars per barrel of oil equivalent ($/boe) is shown below, based on a fuel cost of $1.85/$10^6$ Btu and an O&M cost range of 3 to 4 mills/kWh.

COST OF CONVERSION
($/boe)

Capital Costs	10.3 - 15.5
Fuel Costs	10.2
O&M Costs	1.6 - 2.1
Total	22.1 - 27.8

TABLE J-1-1

SUMMARY OF OIL DESIGNED OIL BURNING POWER PLANTS
OF 200 MW OR LESS CAPACITY

Region	State	Number of Units	Total Capacity (MWe)
I	ME	1	121
II	NJ	2	256
III	DE	1	134
	DC	1	55
	MD	1	162
IV	FL	29	3037
	GA	1	163
V	IL	1	200
	IN	2	218
	MI	1	158
VI	AR	3	338
	NM	3	266
	TX	1	50
VII	SD	1	75
IX	AZ	15	1616
	CA	69	7333
TOTAL		133	14,182

5. Non-institutional Constraints

As discussed earlier, it is unlikely that significant market penetration can be achieved for the conversion of oil designed boilers (200 MW or less) to wood burning using slide-along stoker-fired units. There are a number of non-institutional constraints which include:

a. The power plant may not be suitable to conversion because of space limitations or excessive age of the turbine-generator. Furthermore, matching the required steam conditions (both superheat and reheat) may present some difficulties.

b. The moisture content of wood can often be quite high, making it uneconomical to transport wood more than 40 or 50 miles (3). Therefore, close proximity to the fuel source is an essential feature of wood burning.

c. Certain wood resources may not be practical utility fuels because the wood may possess a higher value as a raw material than as a fuel.

d. Excessively high moisture contents would result in costly handling systems and low boiler efficiencies or costly thermal drying.

6. Institutional Constraints

The institutional constraints on the use of wood as a utility fuel are generally less significant than the non-institutional constraints discussed earlier. Environmental considerations that are of interest include air emission regulations and solid waste disposal regulations. In the case of wood burning, particulate matter is the major concern. Oxides of sulfur and nitrogen are not a major concern, unless the wood is burned in combination with coal or fuel oil.

Solid waste generated by a wood burning utility plant poses a potential hazard both with regard to fire and explosion. Glowing char can cause electrostatic precipitator (ESP) hopper fires if air is allowed to leak into the unit via the hopper discharge port. Also, although ash collected by ESP's has relatively few combustibles, it is very fine and potentially explosive if not handled properly. Ultimate disposal of such solid wastes must be accomplished in an environmentally acceptable manner, in compliance with appropriate regulations.

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J. WOOD IN UTILITIES AND INDUSTRIES

PART 2: WOOD GASIFICATION FOR INDUSTRIES

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J-2-2 Capital Cost Summary for Wood Gasification in Industries
J-2-3 Annual Cost of Wood Gasification Facilities

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J-2-1 Schematic Diagram of Updraft Gasifier
J-2-2 Example of a Large Commercial Wood Gasifier

1. Introduction

The use of wood as a fuel has a long history. It was a primary source of heat until the early part of this century, when fossil fuel reduced its attractiveness.

Industrial wood energy use has primarily been direct combustion for process heat or power generation. Its use in gasification and pyrolysis has been limited to fairly small equipment in the USA, Canada, European countries and some less developed countries. The option of using gasified wood for repowering industrial facilities is discussed in this Appendix, while direct combustion of wood is discussed separately in Appendix J-3.

2. Description

The transformation of solid biomass into a gaseous fuel is not a new concept. The wood gasification process is basically similar to that of coal gasification. There are many different configurations in use for wood gasification but the units that are generating the most interest today are the air blown gasifiers for producing low Btu gas (100-200 Btu/scf). Oxygen blown gasifiers to produce medium-Btu gas (300 to 400 Btu/scf) are excluded from this discussion based on economic and long lead time considerations for an oxygen plant discussed for medium-Btu coal gas (see Appendix F). An oxygen blown wood gasifier has been successfully operating at Union Carbide, Charleston, West Virginia. The oxygen system is technically better and more advanced, but its economics compared to air systems are not generally acceptable.

The several concepts being developed at present for gasifiers include updraft, downdraft, cross flow and fluidized bed gasifiers.

In an updraft unit (Figure J-2-1) the gasifier is filled with wood chips and a small fire is started on a grate above the ash hopper. Just enough air is introduced into the unit to support a glowing bed of charcoal. External steam may be injected into the bed to control grate temperature. In the presence of glowing charcoal, some of the wood moisture as well as externally added steam are reduced to hydrogen (H_2) and carbon monoxide (CO). The products then pass into a pyrolysis zone where tar products are formed. The product gases are further cooled by the infeed prior to exiting from the unit.

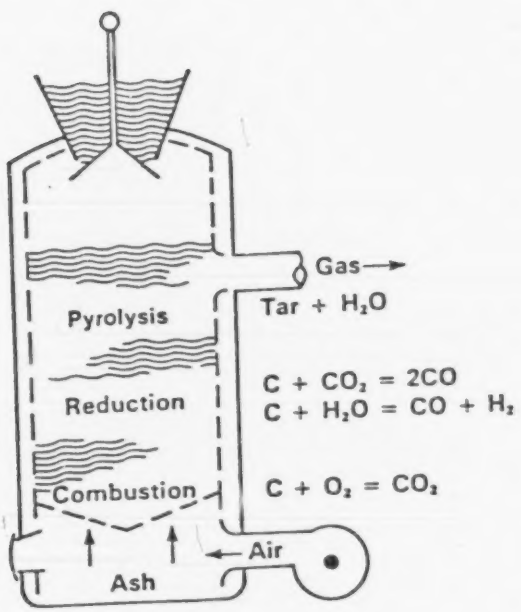

FIGURE J-2-1 Schematic Diagram of Updraft Gasifier

Similar basic principles apply for other types of gasifiers. The overall gasification reaction can be represented according to the (oversimplified) formula:

$$CH_{1.4}\ O_{0.6} = 0.7H_2 + 0.6CO + 0.4C$$

This reaction is slightly endothermic and in practice somewhat more air must be added for combustion to provide the process energy. Because of the nitrogen content the product has a low heating value in the 100-200 Btu/scf range.

A large commercial updraft wood gasifier is shown in Figure J-2-2. Table J-2-1 shows typical feedstock and product gas composition for a low-Btu wood gasifier.

3. Commercialization Assessment

This technology, while proven, has not gained wide application because of operating difficulties and poor economics. Current development efforts, involving about two dozen organizations, are aimed at overcoming these constraints principally for application with wood wastes.

Most of the available systems have capacities less than 30 MMBtu/hr requiring about 50 oven-dried tons (ODT)/day of wood.

4. Oil Replacement Potential

Current use of wood in the industrial sector amounts to 580,000 boe/d assuming oil- and wood-fired boiler efficiencies of 82 and 68 percent, respectively.[16] Unlike bituminous coal, transportation constraints for wood and waste woods are more restrictive because of inherent moisture content and fines involved with waste woods. Clearly, wood gasification in industries will be attractive only in states with large wood and waste wood resources. For screening purposes, the oil replacement potential for wood gasification in industries is assigned the same value (i.e. 340,000 boe/d) as that for potential use of coal gasification in industries. (See Appendix F.)

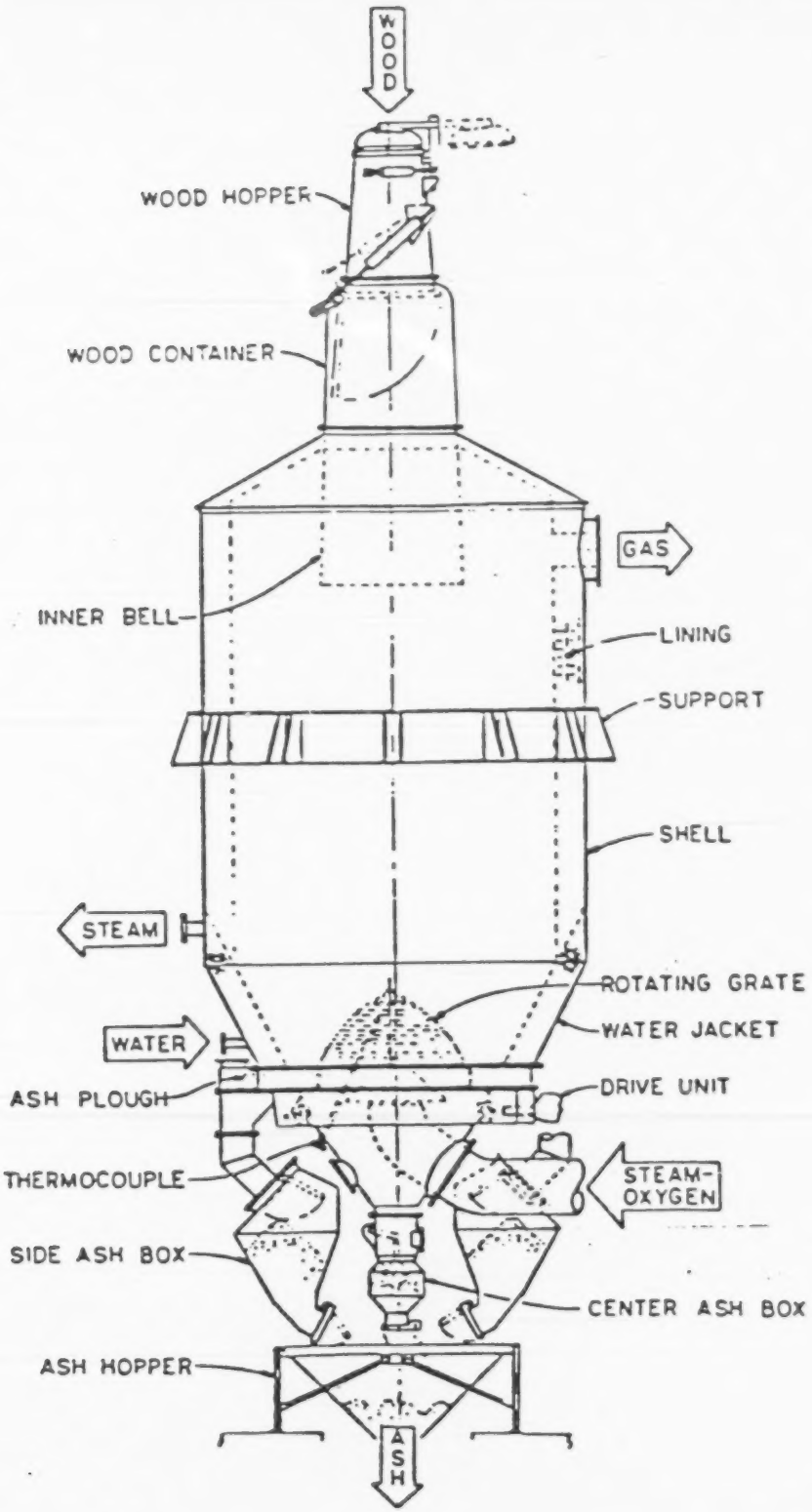

FIGURE J-2-2
Example of a Large Commercial Wood Gasifier
Source: Ref. 11

TABLE J-2-1

TYPICAL RESULTS OF A WOOD GASIFIER

FEEDSTOCK
ULTIMATE ANALYSIS-(wt%)

C	30.90
H	3.60
O	25.35
N	0.70
A	0.05
Ash	1.00
Moisture	38.40
Total	100.00
HHV, Btu/lb	5,410

GAS COMPOSITION (Vol. %, dry basis)

H_2	13.0
CO	29.0
CO_2	6.6
CH_4	4.0
N_2 + Air	47.4
H_2S + COS	- -
Total	100.00
HHV, Btu/scf	176
Scf of dry gas/lb feed	17.2
Lb tar-oil product/lb feed	0.081

Source: Ref. (11).

5. Costs

The capital cost includes three basic components:

a. Boiler retrofitting
b. Wood collection and preparation
c. Gasification facilities.

An existing oil-fired boiler will require mainly burner and draft system modifications for firing low-Btu gas. Based on in-house data, the boiler retrofit costs are estimated to be in the $2500-4000 per MMBtu/hr capacity range (see Appendix F). The boiler efficiency and rated capacity will decrease while firing low-Btu gas. For screening purposes, an efficiency loss from 82 percent (while firing oil) to 75 percent (while firing low-Btu gas) and capacity derating of 30 percent are assumed.

The capital cost (1979 dollars) for wood collection and preparation equipment is reported for two harvesting strategies.[9]

a. Clear cutting to produce chips
b. Residue collection.

The cost of equipment for clear cutting an hourly output of 25 dry tons/hour or 50,000 dry ton/year (annually 850,000 x 10^6 Btu) is $475,000.

The cost of equipment for collecting wood chips obtained from forest residues at an hourly output 10 dry tons or 20,000 dry tons annually (340,000 x 10^6 Btu/year), is $469,800.

Based on the above the cost of equipment to serve 50-100 MMBtu/hr gasifier is roughly estimated to be in the $0.6-1 MM range-equivalent to $10,000-12,000 per MMBtu/hr capacity.

Based on a recently completed design for a 200 MMBtu/hr gasifier [13], industry surveys[18], and in-house G&H data, the capital cost for gasifiers in the 50-100 MMBtu/hr range is estimated to be in the $1.5-4 million or equivalent to $40,000-50,000 per MMBtu/hr gasifier capacity.

With derating of the boiler when firing low-Btu gas the industrial facility will require additional boiler capacity in order to achieve the historically required steam load with comparable reserve margins for reliability and maintenance. The installed costs for the additional 12 and 24 MMBtu/hr boilers are $227,000 and $252,000, respectively[20]. As an alternate to installing new boilers another option is to

switch the boilers back to residual oil when load demand exceeds 70 percent of full load. However, depending on the type of load duration curve and capacity factor this option would result in an inordinately large amount of the required Btu's generated from oil, typically in the 30 to 65 percent range. The capital cost data is summarized in Table J-2-2. It is seen that wood gasification for industrial applications entails capital in the $38,000-50,000/boe/d range.

The annual cost for gasification facilities will depend upon the delivered cost of wood. For screening purposes, we have assumed, conservatively, the delivered cost of wood to be $1.85 per MMBtu including an allowance of $0.35 per MMBtu for transportation. The cost of $1.85/MMBtu is equivalent to about $21/ton of wood containing 50 percent moisture (=$(1.85/MMBtu)x(17 MMBtu/ton of dry wood)x(1/1.5 ton of dry wood/ton wet wood)). Based on this feedstock cost, the first year annual cost for wood gasification are estimated to be $36-43/boe as shown in Table J-2-3.

TABLE J-2-2

CAPITAL COST SUMMARY FOR
WOOD GASIFICATION IN INDUSTRIES

	COST IN 1000 $.	
Gasifier Capacity, MMBtu/hr(*)	54	109
New Boiler Capacity, MMBtu/hr	12	24
Capital Cost		
- Boiler Retrofit	216	273
- Wood Collection & Preparation	650	1,000
- Gasification	2,700	4,360
- New Low-Btu Boiler	227	252
Total Capital Cost	$3,793	5,885
Potential Oil Replaced, boe/d.	76(**)	153
Capital Cost, $/boe/d	49.9	38.5

(*) Based on repowering of 50 and 100 MMBtu/hr oil-fired boilers operating at 82 percent efficiency on oil, and 75 percent efficiency on low-Btu gas.

(**) 50 MMBtu/hr x 35% capacity x 24 hr/day/5.5 MMBtu/boe.

TABLE J-2-3

ANNUAL COST OF WOOD GASIFICATION FACILITIES[1]

	COSTS IN 1000 $	
Gasifier Capacity, MMBtu/hr	54	109
New Boiler Capacity, MMBtu/hr	12	24
Annual Costs		
Capital Charges [2]	629	977
Feedstock Cost [3]	360	727
O&M [4]	197	293
Total	$ 1,186	$1,997
Annual oil replaced, boe [5]	27,900	55,700
Annual Cost, $/boe	0.043	0.036

Notes:

[1] See Table J-2-2 for capital cost and boe/d replaced.

[2] 20 percent annual fixed charge rate on capital cost excluding wood collection and preparation equipment.

[3] Based on $1.85/MMBtu, 85 percent gasification efficiency, 35 percent capacity factor.

[4] Based on 6 percent of capital cost excluding wood collection and preparation equipment.

[5] Boe/d replaced x 365 days/year.

6. Non-institutional Constraints

There exist a number of constraints that would tend to discourage conversion to low-Btu gas.

a. The availability of wood and waste wood proximity to the end-user.

b. The presence of a supplier of feedstock who will guarantee the supply of the required quantity and quality under long term contracts.

c. The technical status of the existing boilers. Some boilers may be close to retirement, so there is no economic justification to build an additional gasification unit, storage facilities, etc.

d. Some boilers may require significant derating so that there will be no economic justification to install new gasification units.

e. Lack of space at industrial plant to build a gasification unit, storage facility, etc.

f. The need for hundreds of new gasifiers and wood harvesting equipment may present constraints to implementation of wood gasification.

g. Guaranteed performance of large gasifiers to eliminate need for oil back-up.

7. Institutional Constraints

The major institutional constraints are related to environmental regulation for ash disposal, and feedstock resource collection and transportation.

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J. WOOD IN UTILITIES AND INDUSTRIES

PART 3: DIRECT WOOD COMBUSTION IN INDUSTRIES

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1. Introduction

The following discussion is limited to the description of wood burning systems for steam generation in the industrial sector, and application of these systems as "slide-along" facilities in existing industrial installations currently burning residual and distillate oil.

2. Recent Wood Burning Installations

Several large wood fueled installations are under construction. California Power and Light Corp. (Fresno) started construction of a 40-50 MW, $70,000,000 grass roots facility which will be the world's largest wood powered electric-generating unit. Some 700 tons/day of pelletized fuel will be burned in this plant.

Dow Corning Corporation (Midland, Michigan) is building a $30 million wood burning cogeneration plant, which started operation in 1982. In this installation, under normal operating conditions, approximately 180,000 tons of wood waste/year derived from low grade timber, sawmill residue, site cleaning and building demolition, with an average moisture content of about 40 percent, will fire the boiler and produce 275,000 lb/hr steam at 1275 psig/900 F. A double automatic extraction/condensing turbine generator will produce up to 22 MW of power, together with 165 psig steam for process and 30 psig steam for space heating. By using wood, the company will save 600,000 bbl/year of fuel oil, reducing its total energy costs by about 25-35 percent. The proposed amount of waste wood used is so small that it is only 0.1 percent of the available wood supply in the 75 mile radius purchase area.

Proctor & Gamble is completing the construction of a waste wood-fired boiler for repowering its cogeneration facility at Staten Island, New York. The boiler will burn 100,000 tons/year of waste wood to produce 240,000 lbs/hr of steam at 950 psig. The capital investment is reported to be $8.5 million.

Several pulp and paper companies are now taking even greater advantage of wood's fuel value. In 1982, for example Chesapeake Corporation (West Point, Virginia) installed a new 350,000 lb/hr wood waste fueled boiler at its pulp and paper mill. The unit will cut their oil consumption from 460,000 bbl/year to 115,000 bbl/year.

New England Electric System is performing a feasibility study for a 10 to 15 MW cogeneration plant at Erving, Massachusetts for Millers Falls Paper Company. The plant will be fueled from existing waste wood sources. Georgia Pacific Corp. has completed an installation of a 140,000 lb/hr steam 400 psig/720 F unit, designed to burn wood wastes.

3. Description

Hog fuel is stored outdoors in piles, or housed in bins or silos designed to hold enough material to sustain boiler operation through a long weekend. High moisture woodwaste usually is kept outside, while dry fines are protected from wind and rain in silos. Some plants have both outdoor and indoor storage for wet hog fuel. The outdoor pile will be relied on by the indoor storage bin for reserve capacity in the event supplies are interrupted, the indoor bin will supply fuel to the boiler automatically.

The fuel handling and storage equipment can be described as follows:

a. Conventional mechanical and pneumatic conveyors and mobile equipment to stack out and recover fuel from storage piles.

b. Storage bins designed to hold more than 1500 units, which can be filled and reclaimed automatically. (A unit is the amount of uncompacted wood waste that fits into a 200 cu ft container.)

c. Storage silos and small bins designed to hold up to about 200 units, which can be filled and reclaimed automatically. The size of an outdoor storage pile reflects the confidence that the owner has in the fuel suppliers and the geographic location of the plant. It also depends on his ability to utilize alternate fuels, if necessary.

The boiler fuel feed system, which transfers woodwaste from storage to the furnace feeders, is critical for any plant fired with hog fuel. It should be designed to accomplish these primary objectives:

a. Reliably deliver a controlled amount of fuel to each feeder consistent with demand.

b. Be capable of biasing fuel flow to one or more furnace feeders to correct for imbalances.

Many wood burning plants have a live bottom surge hopper at the boiler to maintain the fuel inventory needed to meet sudden load increases. These hoppers typically hold a 5-minute supply of hog fuel.

Where live bottom bins are used, the most popular type of discharge system is the multiple screw feeder. Once the hog fuel is delivered to the boiler front, it must be distributed evenly, without segregation by size, among the various feed chutes supplying the furnace distributors.

Distribution of fuel among the chutes normally is performed by flight conveyors, swinging spouts or vibrating feeders.

Fuel demand is determined by the combustion control system and is met either by regulating the flow of material to the vibrating feeders or by varying their vibration frequency.

There are various methods of burning wood wastes:

a. Pile burning

b. Semi-pile combustion

c. Spreader stoker firing (semi-suspension - thin fuel bed burning).

a. <u>Pile Burning</u>

Pile burning is the original method for burning wood refuse and bagasse fuels and is still in use at many locations. Fuel is admitted through a chute in the roof and forms a conical pile on the floor which may have a grate with partial underfire air admission, or may merely be solid refractory with total air admission above the pile, as overfire air. Combustion occurs on the surface of the pile and around the edges.

In this method of combustion, the fuel is burned in a quiescent state and carryover is minimized. The most popular furnace for pile burning is the dutch oven. This type of furnace is capable of burning highly wet wood without resorting to auxiliary fuel. It is installed today only when extremely wet (60 percent moisture or more) unsized bark must be burned in an area where stack emissions are of major concern.

Disadvantages of dutch ovens include high capital cost, high refractory maintenance requirement and manual ash removal.

b. Semi-pile Combustion

The modern semipile burning on inclined water cooled grates permits burning wood refuse measuring up to 4 in. x 18 in. (cross-sectional area). It includes various features to permit automatic operation, semiautomatic sequenced cleaning, and combustion of very wet wood with a minimum or no auxiliary fuel. The inclined water cooled grate has been incorporated in the design of steam generating units having capacities up to 300,000 lb/hr.

Advantages of the inclined grate furnace are as follows:

1) Ability to burn high moisture waste wood with little or no auxiliary fuel.

2) Ability to burn unhogged fuel refuse.

3) Large quantity of wood on grate permitting short outages of conveying equipment and rapid load pickup as required.

4) No moving parts, resulting in low maintenance.

5) Relative insensitivity to changes in fuel sizing or moisture characteristics.

6) Ability to utilize higher air temperature required for high moisture fuels.

7) Greater flexibility with design for auxiliary fuel firing.

8) Low emission levels.

c. Spreader-Stoker Firing

In spreader stoker firing (semi-suspension firing) the main philosophy is to maintain thin burning with the distributors as low as possible in the furnace giving maximum residence time in the furnace while simultaneously minimizing emissions. A pnuematic distributor is commonly used. Air for the pneumatic distributor is normally at a pressure of approximately

25-30 inches wg and is continually pulsed from 2-3 inch wg to this maximum, by means of rotating dampers in air ducts to the distributor. Air vanes are installed to spread air over the desired furnace width (normally 5 to 6 feet). The results are a thin fuel bed evenly distributed over the grate furnace. When distributors are properly designed the entire grate is covered with a fairly even blanket of fuel. Woodwaste is normally hogged until the largest dimension does not exceed 3 inches and is injected into the boiler by pneumatic distributors.

The advantage of semi-suspension thin bed burning is the ability to accommodate rapid load changes. Stoker manufacturers claim that the total amount of excess air required for semi-suspension using vibrating grates can be held to 25-35 percent at the furnace exit. In general, however, the combustion air system is sized to provide at least 50 percent excess air when burning the poorest fuel expected.

There are many types of grates which can be used with spreader stoker firing of which the flat and travelling types are most common. The selection of the type of grate depends primarily on the expected characteristics of the fuel and economic constraints.

Flat air cooled grates are more economical. They can be used for boilers cable of producing about 70,000 lb/hr of steam, and are limited to a heat release rate of 600,000 Btu/hr/sq. ft and primary air temperature of 400 F. Water cooled grates permit heat release rates up to about 1 million Btu/hr/sq. ft and primary air temperatures to 600 F or more. Thus, they allow a much smaller furnace for a given steam demand than do air cooled grates and they can accommodate hog fuel containing up to 55 percent moisture.

Traveling grate spreader stokers feature: (1) continuous ash discharge, (2) accurate load control, (3) rapid response to change in steam demand, and (4) the ability to burn coal on the grate in conjunction with wood.

Grate heat release rates extend from about 1 million Btu/hr/sq. ft for 55 percent moisture fuels to 1.2 million Btu/hr/sq. ft. for 35 percent moisture.

Although there is good agreement among the experts on the total amount of air required for complete combustion of hog fuel, there is no concensus on how that air should be distributed in the furnace. The overfire provides the oxygen and turbulence needed for complete combustion of the volatiles distilled from the fuel, as well as of small carbon particulates carried into the air by the undergrate air. A leading manufacturer of traveling grate spreader stokers recommends 25-40 percent of hot, high pressure (25-30 in H_2O) over-fire air for its equipment.

Moisture level has the greatest impact on the efficiency of woodwaste burning boilers. Depending on the source of the woodwaste, the moisture content varies from 10 percent to 65 percent or even higher.

The fuel moisture content affects both boiler efficiency, and heating value (as fired), and therefore has a major impact on the economics of wood burning.

The magnitude of this impact is shown in Table J-3-1.

TABLE J-3-1

EFFECT OF WOOD MOISTURE CONTENT ON BOILER OUTPUT

Moisture Content as Received	Gross Heating Value (as fired) Btu/lb	Net Heating Value (Heat Available for Steam Prod.) Btu/lb	Boiler Efficiency%	Approx. lbs of 150 psi Steam Per Ton of Wood
15	7440	5767	77	8250
30	6125	4505	73	6109
40	5250	3682	70	4788
50	4375	2860	65	3753
60	3500	2038	58	2196

Temp of entering water - 150 F

4. Oil Replacement Potential

Current use of wood in the industrial sector amounts to 580,000 boe/d assuming oil- and wood-fired boiler efficiencies of 82 and 68 percent, respectively. Unlike bituminous coal, transportation constraints for used and wood wastes are more restrictive because of inherent moisture content and fines involved with waste woods. Clearly, wood combustion in industries will be attractive only in states with large wood and wood waste resources. For screening purposes the oil replacement potential for wood combustion in industries is assigned the same value (i.e., 240,000 boe/d) as that for coal combustion (see Appendix D).

5. Costs

Based on published and in-house G&H data, the capital cost for 60 and 120 MMBtu/hr "slide-along," wood-fired boilers is estimated to be $3.5 and $6.0 million, respectively. Using this data, the capital cost per boe/d replaced is estimated to be $32,000-$38,000 based on the following assumptions:

a. Wood collection equipment requires $0.7 and 1.2 million for 60 and 120 MMBtu/hr wood-fired boilers, respectively, (see Appendix J-2 for rationale).

b. The wood-fired "slide along" boilers replace corresponding sized oil-fired units which have 82 percent efficiency.

c. The boilers have an annual capacity factor of 35 percent so that oil replaced by 60 and 120 MMBtu/hr wood-fired boilers is 112 and 224 boe/d, respectively. (For example, in the 60 MMBtu/hr application, oil replaced = 60 MMBtu/hr X (1/0.82 efficiency factor) X 24 hrs/day X 35 percent capacity factor/5.5 MMBtu/boe.)

The annual costs are estimated to be in the $31 - 34/boe range as shown in Table J-3-2.

TABLE J-3-2

ANNUAL COST FOR DIRECT WOOD-FIRING IN INDUSTRIES

	Cost in 1000	
Slide-Along Boiler Capacity, MMBtu/hr	60	120
Annual Cost		
Capital Charges[1]	700	1,200
Feedstock[2]	500	1,000
O&M[3]	175	300
Total	$1,375	$2,500
Annual Oil Replaced[4]	40,880	81,760
Annual Cost, $/boe	0.034	0.031

Notes:

(1) 20 percent annual fixed charge rate on capital cost excluding wood collection equipment.

(2) Based on $1.85/MMBtu (see Appendix J-2), 35 percent capacity factor and 68 percent wood-fired boiler efficiency.

(3) Based on 5 percent of capital cost excluding wood collection equipment.

(4) Based on 112 and 224 boe/d replaced (see text) and 365 days per year.

Georgia Pacific in Ft. Bragg, N.C. is currently completing the construction of a traveling grate spreader stoker unit generating 140,000 lb/hr steam at 450 psig 750 F. The cost of this unit including wood storage and handling is estimated at about 7.0 million dollars.[15]

6. Constraints

Institutional and non-institutional constraints for direct wood-firing in industries are similar to those described for wood gasification in Appendix J-2. In place of gasifiers the

availability of hundreds of wood-fired boilers might present a constraint.

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K. BIOMASS LIQUID FUELS IN TRANSPORTATION

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K-1 Multiple Batch vs. Continuous Process Comparisions

K-2 Petroleum and Petroleum/Natural Gas Energy Used in Corn Production by Region per Gallon Ethanol Equivalent and Net-Energy Yield for Acre, 1975.

1. Introduction

The principal biomass liquid fuel which is used in the transportation sector is ethanol from agricultural products. Ethanol production in the U.S. comes from two primary feedstocks: agricultural products and ethylene from refineries. Because of its high octane rating, ethanol is now widely used as an octane booster and gasoline extender with unleaded gasoline in a 90 percent gasoline, 10 percent ethanol blend ("gasohol").

In an oil cut-off situation, the ethylene feedstock will be needed in the chemicals industry. It will then suffice to examine the primary source of agricultural feedstocks -- chiefly corn and milo (grain sorghum).

2. Description

Typical yields of ethanol from corn and milo are in the range of 2.5 to 2.6 gallons per bushel. The production process involves conversion of the starch to sugar (glucose and sucrose), and then by fermentation to alcohol. In the process reactions, water is added and carbon dioxide is removed. The protein content is largely retained in the byproduct, distiller's dark grain (DDG), which is sold as dry animal feed or as a syrup food additive. Some agricultural feedstocks produce larger percentages of DDG, such as potatoes, rice, barley, malt, hops and wheat. While many agricultural products can be converted to ethanol, only corn and milo are of major importance because of the favorable economics involved in their conversion to ethanol compared to wheat and sweet sorghum. Of these two feedstocks, milo also has a limited use since the DDG derived therefrom is indigestible to most foraging animals.

In the process of ethanol production, the feedstock is ground, mixed with water and pretreatment enzymes and acid, and cooked to convert the starches to sugar. The converted mixture is then cooled and introduced to fermentation vats wherein fermenting enzymes are introduced. The beer is then heated and distilled in a "beer still". After a two-step distillation, the product ethanol is at about 80 to 90 percent (160° to 180°) quality, and is further refined to 199° in an azeotropic distillation column, generally with heptane. The final product, anhydrous alcohol, is denatured with gasoline for sale.

The "bottoms" from the beer still contain the DDG, which is usually dried in centrifugal separators, rotary kilns or in a vacuum dehydrator.

The process also produces some heavy alcohols and aldehydes (fusel oil) which are generally burned in the plant, as they "gum-up" fuel-grade ethanol. In commercial drinking alcohol plants, these provide the "taste" preference and are excluded from this overview evaluation of fuel alcohol plants.

There are two primary process types for ethanol production via fermentation, batch and continuous fermentation. Vogelbusch of Austria has a continuous process that is the basis of Brazilian ethanol production. Butler, Katzen, and many commercial distillers in the U.S. utilize a batch process, which is more efficient in conversion yields, but more costly to build, operate and maintain. The batch and continuous process types are compared in Table K-1.

DDG is the primary byproduct. Other byproducts of ethanol production can be fertilizers (ammonium sulfate), carbon dioxide, and pharmaceuticals, but do not represent critical elements in the overall economics.

3. Commercialization Assessment

Commercial-scale ethanol plants have been built, and designs are available up to 100 million gallon-per-year (GPY) scale. A large number of facilities are in operation, and U.S. fermentation capacity is now over 600 million GPY. The amount available for power alcohol production is about 160 million GPY, and latest estimates indicate that monthly sales of gasohol were 121 million gallons in July 1982, double that of July 1981. The average plant size is 5 to 10 million gallons per year, and 5-year performance bonds are commercially available for 2.5+ gallons per bushel of corn yield.

Average crop yield for corn is about 100 bushels per acre per year. Recent studies claim that 66 million acres of pasture land and light forest could be brought into production with corn, yielding a potential of 17 billion gallons of ethanol per year. However, it could be argued that preparation costs for this currently uncultivated land (for clearing, proper drainage, and tillage) would increase crop costs.

In addition, there is the controversial question as to whether ethanol production via crop fermentation exhibits energy effectiveness. Table K-2 shows energy used in corn production for various regions of the country. Farm usage averages about 80,000 Btu per bushel of corn [range: 50,000 to 150,000].

TABLE K-1

MULTIPLE BATCH VS. CONTINUOUS PROCESS COMPARISON*

Raphael Katzen Assoc.	Vogelbusch-Bohler Bros.
Feedstock Selection	
Only dry grain for dry milling (Add $35MM to plant cost if wet milling included for other feedstock)	Dry grain, broken or wet grain, wheat, potatoes, etc.
Conversion to Cellulose Based Feedstock	
No such alternative feedstock offered in same plant system	Encouraged cellulose feedstocks in new and future plant design
By-Product Options	
One By-product, distillers' grains offered - no alternatives	Gluten, corn oil, sweetner, corn CO2, thin starch and distillers' grains at the owner-operator's option
Fermentation System	
Multiple Batch	Continuous
Steam Use Per Gallon Of Alcohol	
31.7 lbs/gal	28 lbs/gal
Personnel Required	
130 people (50 MM gal plant)	80 people

*Information from published reports and available company brochures.

TABLE K-2

ENERGY USED IN CORN PRODUCTION BY FARM PRODUCTION REGIONS, 1974

Fuel Types	Farm Production Regions									
	Pacific	Mountain	So. Plains	No. Plains	Lake States	Corn Belt	Delta States	Northeast	Appalachian	Southeast
Total Acreage (1,000)	293	583	891	9,809	9,980	33,680	239	2,356	3,896	3,467
Gasoline kBtu/acre	798	944	1,213	861	1,281	1,405	492	1,327	1,014	961
Diesel kBtu/acre	1,320	1,472	1,285	1,866	637	630	2,089	1,475	1,131	1,150
Fuel Oil kBtu/acre	-	-	-	0.22	3.2	13	50	13	191	109
LP Gas kBtu/acre	54	520	491	1,351	642	822	136	266	317	284
Natural Gas kBtu/acre	77	3,896	6,250	1,562	12	51	197	82	215	115
Electricity kBtu/acre	2,831	913	467	288	45	43	29	-	34	32
Invested Energy kBtu/acre	4,703	4,136	4,114	4,027	3,591	4,246	4,452	2,928	3,509	2,626
Total-kBtu/acre	9,783	11,881	13,820	9,977	6,211	7,210	7,445	6,091	6,411	5,277

(*) Includes energy to manufacture and deliver fertilizers and pesticides.

Sources: Reference (4)

An integrated batch process (Katzen) utilizes 300 tons per day of coal and 8300 kW to process 59,000 bushels of corn per day, or about 140,000 Btu per bushel. Thus, an average energy input of 220,000 Btu per bushel (80,000 Btu/bushel for farm usage plus 140,000 Btu/bushel for processing) represents an investment of about 125,000 Btu per gallon of ethanol (based on 2.6 gallons of ethanol per bushel) excluding energy required for transporting corn to distillaries and ethanol to its point of end-use.

Since ethanol has a lower heating value of 75,670 Btu/gal, it is apparent that energy efficiency in producing ethanol from corn will depend upon plant specific issues. With highly efficient grain production, siting of the process facility near to farms, and use of the most efficient processing techniques, net energy production for ethanol could be made less negative. Furthermore, the use of coal-based steam and electricity in a cogeneration facility could be another option. In an oil cutoff crisis situation, the likelihood is that the "net energy balance" issue may not be the major criteria as long as coal is the primary fuel for steam and electricity generation.

The current technology for grain ethanol is relatively simple and straightforward. Operations and maintenance require specialized skills, but training can be rapid. There are few, if any, requirements for special materials and alloys. However, cooking vats are usually manufactured with stainless steel. Large-scale (>20 MMgal/year) facilities will require large, field erected distillation columns, rotary kilns, vacuum dryers, etc. that have one to two year lead times. These equipments could cause some bottlenecks in production if rapid expansion were mandated.

4. Oil Replacement Potential

Feedstock for grain ethanol production is limited. Approximately 10 billion bushels of grain are grown each year, and only about 20 percent is exported. About 60 percent of the grain is corn.

To meet a 200,000 boe/d requirement, 4.6 billion gallons of ethanol are needed yearly utilizing 1.9 billion bushels of grain -- 19 percent of U.S. production. This incremental production must come from new cropland. Hybrid seed, pesticides, fungicides, and fertilizer are already in widespread use in the U.S., so that average production yields are not expected to improve substantially as exhibited in the past. Since soybean can be substituted by the byproduct DDG, the acreage of new cropland necessary will be offset by lower soybean acreage requirements. For ethanol production levels

below 4 billion gallons per year, 80 percent of the extra corn acreage needed would be offset by lower soybean production. Above this level of production, each additional acre of corn production will require an additional acre of farm production because the U.S. protein concentrate market would probably be saturated and exports to Europe would probably need to be curtailed to protect European soybean industries. Thus, to produce 4.6 billion gallons of ethanol, about 6 million acres of new cropland will be necessary.

In addition, 10 to 15 million acre-feet of water would be needed for irrigation, which could pose serious problems in some regions.

The above oil replacement potential discussion reflects differences in thermal properties of gasoline and alcohol (i.e., lower heating value of about 115,000 Btu/gal for gasoline vs. 75,670 Btu/gal for ethanol). If differences in thermal properties are neglected (recognizing that it is controversial issue) for typical 90/10 gasoline/ethanol blends, we could argue that 1 gallon of ethanol can replace 1 gallon of gasoline. This will imply that to meet a minimum of 200,000 boe/d shortfall requirement, about 3.0 billion gallons of ethanol will be needed per year which will utilize about 1.2 billion bushels of corn, or about 12 percent of U.S. production. For the purposes of this overview analysis, the Btu difference in gasoline and ethanol is considered in the following analysis.

Current power alcohol production, about 160 million GPY, is equivalent to a gross production of 7000 boe/d. Expanding capacity to 200,000 boe/d (gross) would likely take at least 5 years, but probably longer. Lead times may be shortened for equipment, but institutional/non-institutional constraints, cost and physical factors may preclude shortening the implementation time.

5. Costs

Current ethanol prices average $1.60 per gallon, or $120/boe. Without subsidies (averaging 90¢/gallon), production costs are reported to be in the range of $1.30 to $1.50 per gallon. In the event of a major oil cutoff, the increase in farm and transportation energy costs as they effect current corn prices is estimated at $1 per bushel, or 40¢ per gallon of ethanol. Thus ethanol production costs without subsidies could approach $1.70 to $1.90 per gallon, or $125 to $140/boe. Based on current retail price levels, this would result in an ethanol price of approximately $2.00 per gallon or $150/boe (with subsidies). Ethanol production facilities cost between $0.80 and $1.40 per gallon per year

capacity or about $4 to 7 billion for a 200,000 boe/d level of production.

Additional capacity in the chemical industry for fertilizers, pesticides and fungicides (about two million tons per year) would require another $1 billion in indirect capital. Similarly, 6 million acres of new cropland would require $1.5 billion indirect capital based on average conversion costs of $250/acre. To the extent that this cropland is taken from set aside acreage, these indirect conversion costs would be lowered accordingly.

6. Non-institutional Constraints

A major shift to grain ethanol production places pressure on food prices, land prices, and capital markets. Labor and materials availability is assured, although some strain may be exhibited in farm machinery sectors. Transportation networks may also be structured in moving the grain and product ethanol from the Mid-West to coastal refineries.

Compared to other oil replacement technologies, ethanol production is rated "medium" with regard to any strategic material constraint (see Section IV.B.).

Capital intensity is also a major limiting factor. Ethanol production facilities cost about $5 billion for the 200,000 boe/d level of production. Capital for new cropland acquisition and additional capacity in the chemical industry for fertilizers, pesticides, and fungicides would also be required.

7. Institutional and Regulatory Constraints

Land and water use impacts will be major if this technology is implemented at large scale. Wastewater from farms is already the leading cause of lake, river, stream and ocean pollution. Acquiring large blocks of contiguous land is also time-consuming from a siting point of view. Ethanol conversion plants produce large quantities of liquid, solid and gaseous wastes which would need disposal to meet environmental regulations. Water consumption would also be excessive to implement this technology, and water rights acquisition may become a problem.

Current tax laws favor ethanol production, with 40¢ per gallon in direct federal subsidy, an average of 30¢ per gallon for state subsidies, and tax credits, grants and subsidized financing worth up to 20¢ per gallon. It is recognized that these policies represent another form of farm subsidy, but these will expire by the early 1990's. In a

crisis situation, additional government subsidies may be required to reduce the apparent price of ethanol to low levels acceptable to consumers.

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L. NATURAL GAS AND LIQUEFIED PETROLEUM GAS IN TRANSPORTATION

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1. Description

Both compressed natural gas (CNG) and liquefied petroleum gas (LPG) can power existing vehicles with no vehicle modifications other than those required to store and deliver the fuel[1-6]. The basic principles of vehicle modification are similar, but the fuel delivery system and resource potential present major differences.

CNG vehicle fuel is obtained from pipeline natural gas which is compressed to 3600 psig remaining in the gaseous state in storage vessels or cascades, and subsequently delivered to vehicle storage tanks at 2400-2500 psig. This vehicle tank pressure is not required for operation of the vehicle on natural gas, but simply to increase the energy density to a point where the size of the storage tanks is practical. Despite this level of pressurization, the natural gas stored at 2500 psig has only 23 percent of the energy content of gasoline on a volume basis.[7]

LPG consists of propane, propylene, butane, butylene, ethane-propane mixtures, propane-butane mixtures and isobutane produced at crude oil refineries or natural gas processing plants, including plants that fractionate raw natural gas plant liquids.[8] Approximately 35 percent of the LPG is derived from refineries and practically all of this is consumed as feedstock in petrochemical plants and as fuel in the refining operations.[3] As a substitute fuel for replacement of petroleum based fuels the LPG considered in this evaluation is that derived from natural gas processing plants only, i.e., the approximate 65 percent LPG balance.

There are four grades of LPG available[9]:

a. Commercial propane which is predominantly propane and/or propylene;

b. Commercial butane which is predominantly butanes and/or butylenes;

c. Commercial B-P mixtures which are predominantly mixtures of butanes and/or butylenes with propane and/or propylenes; and

d. HD-5 propane which has not less than 90 liquid volume percent propane and not more than 5 liquid volume percent propylene.

HD-5 propane is the only grade of LPG designated for use in automotive engines and was devised to assure uniform quality of propane used as fuel to avoid engine damage. Although

only 8.5 percent of the LPG in 1981 was used as engine fuel, 50 percent of the LPG produced is Grade HD-5.[25] However, much of the designation of propane as HD-5 is based on the market for HD-5. If a larger market were developed, 76 percent of LPG could be designated for automobile use.[3,25] The distribution network for LPG is currently structured such that it is the responsibility of the retail marketer to assure that Grade HD-5 is provided for automotive engine use.

As opposed to natural gas, LPG exhibits vapor pressure characteristics such that it can be contained as a liquid at ambient temperature under a moderate pressure of 150 psig and has a much higher energy density than CNG. Nevertheless, LPG has only 72 percent of the energy density of gasoline on a volume basis.[7]

Spark-Ignition (SI) vehicles converted to CNG or LPG fuel can maintain a dual fuel capability, that is equipped with a fuel selector control panel to switch alternately from either gasoline to the gaseous fuel as desired. The conversions are completely closed systems that deliver gaseous fuel through a system of regulators and valves from pressurized storage cylinders located in the automobile trunk between the rear wheels, on the underside of a bus or large truck, or in the bed of a pickup truck. No internal engine modifications are required for the conversion and when in the gasoline mode the normal function of the carburetor is unaffected. For compression-ignition (CI) vehicles, that is, those using diesel fuel, the modifications are not as straight-forward[5, 9, 10]. High octane CNG and LPG have a low ignition quality (low cetane number) and ignition aids must be employed. The ignition aids can be chemical fuel additives, spark plugs, glow plugs or other heated surfaces, or injection of 10 to 15 percent diesel fuel (on an energy basis) to ignite the CNG or LPG primary fuel. Satisfactory operation of CI engines with CNG or LPG over the wide range of operating conditions required by a vehicle is difficult, and commercial conversion kits for CI vehicles are not available. Thus, our discussion of vehicle conversions is limited to SI vehicles where an extensive number of conversions have been performed.

There are several vehicle conversion system designs for utilizing CNG in a dual-fuel vehicle. Principal differences among the various conversion system designs are as follows:

a. Method of gas-air mixing--in a separate mixer or in the carburetor venturi.

b. Pressure regulator design--two or three stages, separate or integral packaging, existence or type of provision for NG heating.

c. Means of adjustment of the idle gas-air mixture.

d. Provisions for fuel shutoff in the event of loss of electric power or manifold vacuum.

e. Method for fuel switchover -- mechanical or electrical activation.

Figures L-1 and L-2[11] illustrate the most popular[12] conversion system in the United States. The thirteen (13) items of Figure L-2 can be grouped into five basic functions: 1 - high pressure CNG storage and delivery (items 1, 2 & 3); 2 - pressure/flow regulation and low pressure CNG delivery (items 4, 5, 6 and 7); 3 - gas-air mixing (items 8 and 9); 4 - fuel selection and measurement (items 10, 11, and 12); and 5 - refueling (items 13, 12, 3, 2 and 1).

The various conversion system designs are essentially identical in the area of fuel storage. Under storage conditions approximately 1 cu. ft. of CNG is equivalent to 1.5 gallons of gasoline on an energy basis with typical cylinders containing the equivalent of 2.5 to 3 gallons of gasoline. Depending on the driving range required, the number of storage cylinders in vehicles is generally 2-3 for passenger cars, 2-4 for pickup trucks and vans and 2-8 for larger trucks. The storage cylinders must meet DOT Specification DOT 3AA, but it is important to note that foreign CNG vehicle cylinders do not meet this requirement and are lighter than corresponding domestic cylinders. Each cylinder is equipped with a high pressure ball valve which allows manual shut-off of CNG as an added safety feature.

In the area of pressure/flow regulation there are important design differences among the conversion designs. The design shown in Figure L-2 consists of three distinct components for pressure regulation and fuel flow. Other domestic CNG systems as shown in Figure L-3[13, 14] use three stages of pressure regulation and a solenoid valve for flow control, all contained in a single housing. This single housing design permits use of engine coolant heating to prevent freezing of any moisture in the CNG. The design of Figure L-2 requires either drying of the pipeline gas before compression or adding a small amount of methanol to the CNG leaving the compressor.[5] However, during startup (no heating from engine coolant) the single housing designs are also susceptible to icing and suppliers recommend starting

the engine on gasoline if CNG has not been dried or had a methanol additive.

The three-stage pressure regulator has an idle flow adjustment screw and a valve between the second and third stages to increase gas flow at high demand. The separate regulator design has no provision for mixture enrichment at wide open throttle. Whether self-contained or as part of the regulator housing, the natural gas solenoid valve controls the flow of CNG to the carburetor, and hence the power produced, as dictated by the accelerator pedal position.

One domestic CNG system does not utilize a gas-air mixer ahead of the existing gasoline carburetor.[5] Instead of employing a mixer, holes are drilled in the carburetor to feed the natural gas directly to the carburetor venturis where gas-air mixing takes place.

In all systems vacuum switches are employed to close the CNG solenoid valve when the engine stops. This safety provision is bypassed during engine startup. Switching from CNG to gasoline and vice versa is rapid either through mechanical/electrical or all-electrical switches which control the gasoline and CNG solenoid valves.

Refueling with CNG is done by two methods which are often both available at the same refueling station.[1,2,4,5,6,9-14] The fast-fill system allows one or two vehicles to be refueled in 2 to 5 minutes from a cascade of high-pressure cylinders previously filled by a compressor to approximately 3600 psig. The storage capability of the cascade permits the fast-filling. Slow-fill or time-fill is used to simultaneously refuel a large number of vehicles. Depending on the number of vehicles and the capacity of the compressor the time-fill generally takes 4 to 14 hours. Typical components of a CNG refueling station are shown in Figure L-4.[13]

Vehicle conversion to LPG consists of four basic components ([15,16]) as shown in Figure L-5: fuel tank, filter fuel lock, vaporizer regulator and gas-mixer/carburetor. Similar to CNG systems LPG fuel systems are equipped with a variety of safety devices and shutoff valves that operate automatically should a fuel line rupture or the engine stop running. The tanks are tested at a pressure 1.5 times the design pressure, which is far in excess of any pressure reached in service.

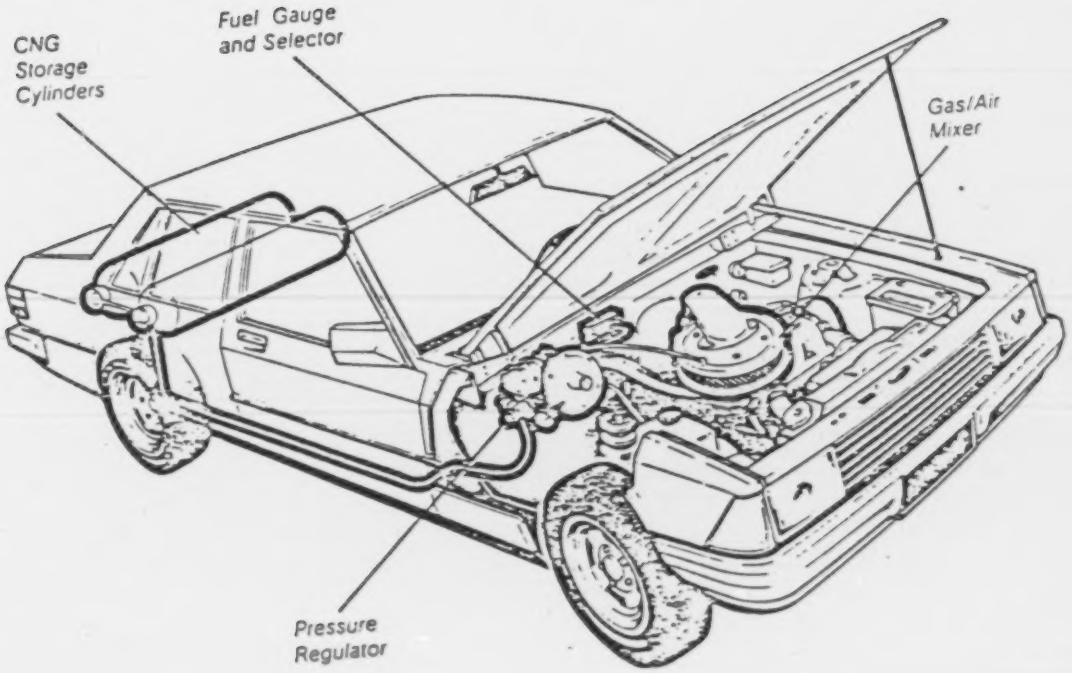
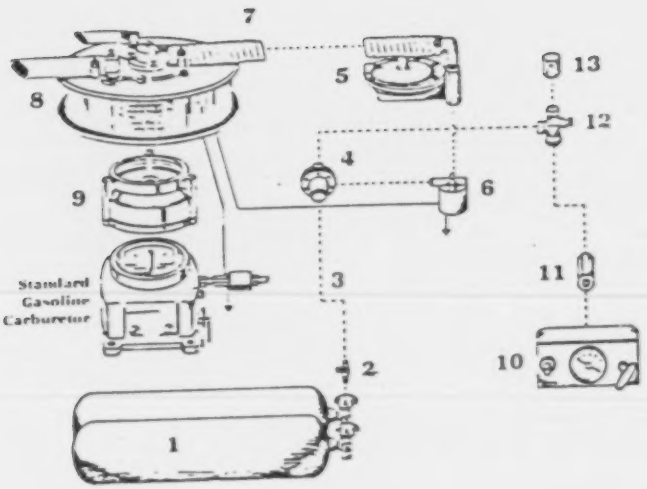


FIGURE L-1
Typical CNG Passenger Vehicle Conversion

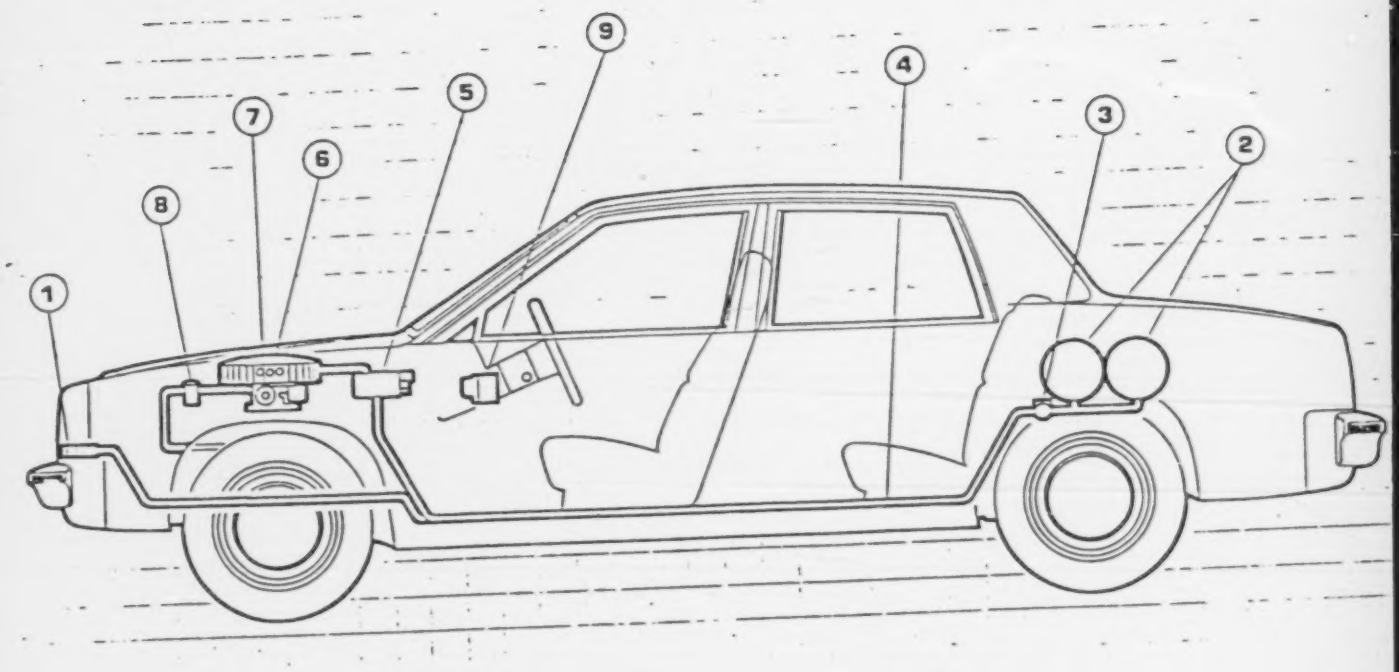
Source: Ref. 11



1. **CNG STORAGE CYLINDERS:** CNG is stored on board the converted vehicle at 2,400 psi in U.S. Department of Transportation 3AA rated cylinders.
2. **MANUAL SHUT-OFF VALVE:** Each CNG storage cylinder is equipped with a high pressure ball valve which allows manual shut-off of CNG as an added safety feature.
3. **FUEL SUPPLY LINE:** The CNG supply line is made of high pressure steel tubing with a minimum working pressure rating of not less than 3,000 psi and a test pressure rating of 12,000 psi. It is ¼" thick and is manufactured to Society of Automotive Engineers specifications.
4. **FIRST STAGE REGULATOR:** The primary regulator reduces CNG from 2,400 psi storage pressure down to 60 psi. It is tested to withstand pressures in excess of 15,000 psi.
5. **SECOND STAGE REGULATOR:** The secondary regulator reduces CNG from 60 psi down to less than one pound working pressure. This regulator design has been used by the gas utility industry for many years and is rated for inlet pressures up to 125 psi.
6. **CNG SOLENOID VALVE:** A 12 volt DC pilot-operated solenoid, located between the first and second stage regulators, controls the flow of CNG into the system.
7. **VAPOR HOSE:** The vapor hose supplies CNG from the second stage regulator to the gas/air mixer. It is impervious to CNG and capable of sustaining five times the maximum service pressure.
8. **GAS/AIR MIXER:** This specially designed unit operates on the diaphram controlled variable venturi principle. It meters CNG into the carburetor as required for combustion and maintains the proper fuel to air ratio at all levels of engine demand.
9. **CARBURETOR ADAPTOR:** This unit adapts the gas air mixer to the standard carburetor in a straight-set or off-set configuration.
10. **FUEL SELECTOR CONTROL PANEL AND GAUGE:** The dash-mounted panel incorporates a sturdy push-pull cable with a handle for switching from one fuel to the other. A pressure gauge indicates the amount of CNG remaining in the vehicle.
11. **GAUGE ISOLATOR:** The isolator is installed in the high pressure fuel supply line behind the pressure gauge to prevent CNG from entering the passenger compartment.
12. **COMBINATION VALVE:** The combination check and fill valve allows CNG to flow through the fuel supply line to the storage cylinders and functions as a relief device to guard against overpressurization. It also automatically seals the system after refueling.
13. **REFUELING CONNECTION:** The refueling connection is designed to receive a probe-type refueling coupling and is equipped with an interlock switch to prevent the vehicle from being started inadvertently during refueling.

FIGURE L-2
Components of CNG Vehicle Conversion

Source: Ref. 11



1. Natural gas is compressed and enters the system through the natural gas fill valve.
2. It is transferred to high pressure cylinders located in the rear of the vehicle.
3. When natural gas is needed by the engine it leaves the cylinders and passes through the master manual shut-off valve.
4. The gas goes into the high pressure fuel line and enters the engine area.
5. Gas enters the pressure reducer and is reduced from 2,400 psi to atmospheric pressure. The natural gas solenoid valve shuts off natural gas when the engine is not running or when the engine is powered by gasoline.
6. With the natural gas solenoid valve opened, the natural gas passes through the pressure reducer into the gas mixer.
7. Natural gas mixed with air flows down through the gasoline carburetor and enters the engine's combustion chambers.
8. Gasoline supply to the carburetor is controlled by the gasoline solenoid valve.
9. A fuel selector on the dash permits selection of CNG or gasoline.

FIGURE L-3
CNG Vehicle Conversion Utilizing Three Stages of Pressure Regulation

Source: Ref. 13

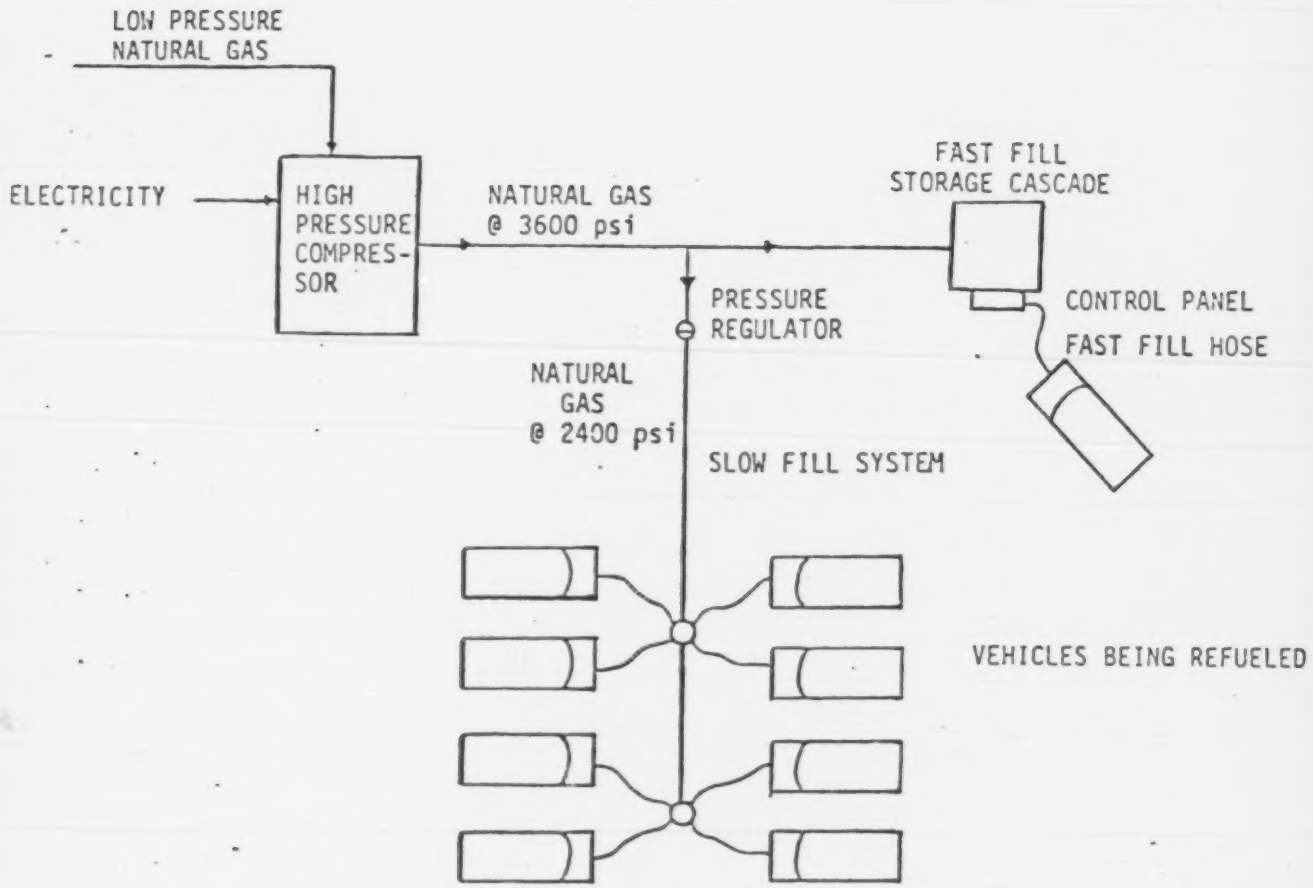


FIGURE L-4
Typical Components of CNG Refueling Station

Source: Ref. 13

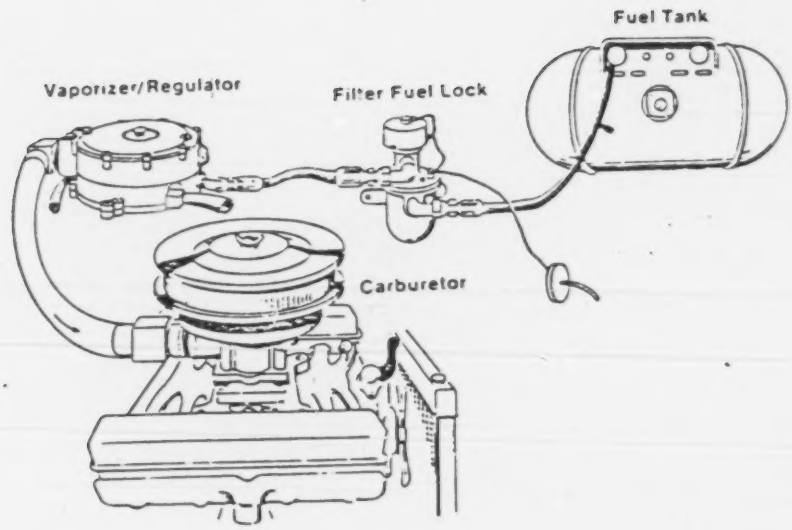


FIGURE L-5
Components of LPG Vehicle Conversion

Source: Ref. 15

The vaporizer/regulator reduces fuel pressure in the system and vaporizes the LPG with further enhancement of this vaporization through heat generated by the engine's cooling system. A gas-air mixer (not shown in Figure L-5) is mounted ahead of the gasoline carburetor.

Refueling with LPG is somewhat more complex than with gasoline because the filling station and vehicle storage tanks are pressurized. However, because LPG is liquid and at much lower pressures than CNG, LPG does not have the CNG time-fill problem and is not as complex a filling operation.

2. Commercialization Assessment

Both CNG and LPG powered vehicles are a commercial reality in the U.S.A. and worldwide. There are approximately 20,000-30,000 CNG vehicles in the U.S.A. and 300,000 to 400,000 worldwide.[5,10,13] Worldwide use is concentrated mainly in Italy with New Zealand planning to convert 150,000 fleet and private vehicles to CNG by 1985. There are at least six (6) suppliers of CNG dual-fuel conversion kits in the U.S.A.[5, 10] with an additional one each in Canada and Italy. A single-fuel CNG vehicle called the AFV (Alternate Fuel Vehicle) is the latest addition to Ford Motor Company's experimental fleet.[7,17] The CNG powered AFV vehicle holds the equivalent of 6.6 gallons and has a range of 210 miles. Commercialization of the AFV is several years away.

CNG conversion kits are sold domestically to the fleet vehicle market and not to the private one. Included in the selling price is a training program for mechanics associated with the fleet operator to install the equipment and service the vehicle.[4,12,13] For operability and safety reasons this training is important and it is possible that a bottleneck created by a lack of adequately trained mechanics may develop if an attempt were made to quickly convert millions of vehicles. Many components of the CNG conversion kit consist of commonly available items such as regulators, valves, tubing and hoses, gauges and venturi mixers which are not anticipated to create a supply bottleneck. Storage cylinders, carburetor adaptors, which vary among automobiles, compressors and foreign manufactured, proprietary regulators may present a production bottleneck under an accelerated vehicle conversion scenario. CNG conversions do not rely on the availability of strategic materials.

CNG vehicles have demonstrated acceptable operation and safety characteristics [5,6,9,10,13] as listed below:

a. Dual-fuel operation and switching has successfully permitted extensive use of CNG as fuel while maintaining

the desirable, extensive driving range characteristic when in the gasoline mode.

b. Limited fuel dilution of engine oil - during cold start and cold weather liquid fuel deposits on cold cylinder walls and dilutes the fuel oil. This does not occur for a gaseous fuel.

c. Improved fuel economy in pre-1975 vehicles and essentially identical fuel economy as gasoline in late model automobiles. Power reductions of 10-20 percent occur with CNG vehicles, however, because the engines are not optimized in terms of spark timing and compression ratio for the higher octane fuel.

d. Substantial reduction in emissions.

e. Reduced engine maintenance - no carbon buildup.

f. Impressive safety record - In the U.S.A. of an estimated 1360 collisions involving CNG vehicles, there were no failures or fires involving the CNG fuel system. Over 183 of these collisions were rear-end ones, but none caused a failure of the CNG system. The safety record compiled in Italy for CNG vehicles is excellent.

The use of LPG as a vehicle fuel is more commercially mature than CNG in terms of longevity and number of vehicles in operation. In Italy alone there are approximately 700,000 vehicles operating on LPG.[5] In this country accurate statistics have not been kept until recently, but it is estimated that 1.5 million vehicles are LPG fueled.[19] In 1981 in the U.S.A. alone 300,000 vehicles had LPG systems installed.[15] In 1982 Ford Motor Co. began selling LPG fueled cars in Canada and the U.S.A.[3,7,18] Ford had first-year sales of 1500 cars and projects 6000 cars will be sold in 1983. [25] Ford dealers provide a directory of nationwide LPG fuel stations that currently exist mainly for the recreational vehicle and home cooking market.

The bottlenecks in trained labor and some components that may occur with rapid deployment of CNG vehicles are not expected to be as severe with LPG because a more extensive infrastructure for engine modifications and fuel stations already exists and the resource potential of LPG is lower than that of CNG. The National Fire Protection Association (NFPA) has developed standards governing both installation procedures and the four major equipment components of the LPG vehicle system. The National LP-Gas Association has a program that certifies installers to safety standards developed by the NFPA.[15] The American Gas Association has begun efforts to develop similar industry-wide standards regarding the design, manufacture, installation and performance of CNG fuel systems.[10]

3. Oil Replacement Potential

The basis for assessing oil replacement potential differs for CNG and LPG vehicles because a fuel distribution exists for LPG vehicles that serves the private automobile market whereas for CNG one does not. Therefore, the CNG oil replacement potential is based upon an assessment of the number of vehicles that can be easily adapted to CNG powering, whereas, the LPG oil replacement potential is based on the additional amount of LPG that will be available for vehicle fuel and the ability to expand the delivery capacity of the LPG station network for private and fleet vehicles.

The oil replacement potential of CNG vehicles has been estimated [5] based on the fleet potential solely since it was assumed that widespread private CNG vehicle use will not occur in the U.S.A. unless public fueling stations become commonly available. In Italy public use of CNG vehicles has been in effect for about 40 years but there has been strong governmental support. In a subsequent section cost data for developing a network of public CNG stations and for individual refueling in private homes in the U.S.A. are presented and compared to the fleet vehicle cost information.

The total fleet vehicle market can be divided into passenger car fleets and truck and bus fleets. There are six types of passenger car fleets: (1) business, (2) rental, (3) government (federal, state, local), (4) police, (5) utility and (6) taxi. A detailed tabulation of the number of passenger car vehicles in fleets of 10 or more in 1981 is shown in Table L-1.[5] Based on the average daily mileage and fuel economy, with the exception of taxis, all of these vehicles can be adequately fueled by two CNG cylinders, which fit neatly into vehicle trunks in current installations. Taxis may require 3 or 4 cylinders depending

on use and the improvements in fuel economy anticipated in the future.

A passenger car fleet is defined as a group of four or more cars that can be classified as belonging to one of the car fleet types above. Table L-2 compares the number of total fleet cars to those fleets with 10 or more cars and projects each level for 1985. Based on the average fuel economies and average annual mileages of Table L-1, the gasoline consumption (diesel engines not easily repowered with CNG) is anticipated at 780,000 bbl/d and 300,000 bbl/d for the total fleet market and for fleet of 10 cars or more, respectively, in 1985.

The other major fleet category is truck and bus fleets. Table L-3 shows the total private and commercial truck population (all weight classifications) and the truck fleet population (6 or more trucks) existing in 1977 and projected for 1985. Included is the estimated fuel consumption for each year. The gasoline consumption for private and commercial fleet trucks is anticipated to be 250,000 bbl/d in 1985. Government fleet trucks are anticipated to add 18,000 bbl/d, bringing the total to 268,000 bbl/d.

The bus sector consists almost entirely of fleets with repetitive daily missions. However, fuel consumption of this group is low compared to other fleets and 60 percent of the fuel is diesel as shown in Table L-4. In 1978 the gasoline consumption of bus fleets which is almost entirely for school vehicles, was only 27,000 bbl/d. Since school population growth is relatively stagnant, and may in fact be decreasing, the 27,000 bbl/d consumption level is assumed valid for 1985.

The gasoline replacement potential of each category of fleet vehicle is summarized in Table L-5. The gasoline consumption for each is reduced by two factors: 1) the fraction of time that CNG is powering the dual fuel vehicle and 2) the expected fraction of vehicles that reasonably can be converted in a 5-year period. The first factor is assumed to be 95 percent because current CNG usage in dual-fuel vehicles is 75 to 80[5] percent and in a crisis situation it is reasonable to expect the higher usage rate. For the second factor each fleet type was examined with regard to its perceived conversion penetration. For example, the salesperson-owned and leased vehicles shown in Table L-1, although considered fleet type vehicles, are more like private automobiles in their driving and refilling needs.

TABLE L-1

FLEETS OF 10 OR MORE PASSENGER CARS IN 1981

Fleet Type	Number of Vehicles, Thousands	Average Travel Per Car			Average Retention Period, Months	Fleet Fuel Economy, MPG
		Annual, × 1000 Mi	Daily, Mi			
			5 Days/Wk	7 Days/Wk		
Business						
Salesperson-Owned	340	23	88	63	NA	19
Leased	2192	28	107	77	27	19
Company-Owned	655	18	69	49	36	19
Daily Rental	491	16	61	44	14	19
Government						
Federal	107	13	50	36	72 (Max)	18
State and local	500	17	65	47	48	17
Police						
State	40	27	104	74	30	18
Local	213	25	96	68	36	12
Utility	162	12	46	33	60	16
Taxi	155	40	153	110	36	14
Total/Average	4855	23.4	90	64		

Source: Ref. 5

TABLE L-2

PASSENGER CAR FLEET PETROLEUM FUEL CONSUMPTION

PARAMETER	CALENDAR YEAR 1981	1985
Fleet Cars, Millions		
Total	12.59	12.94
Fleets of 10 or more	4.85	4.95
Diesel Fraction of Fleets		
New Car Sales	0.071	0.200
Cumulative	0.05	0.162
On-Road Fuel Economy, MPG		
Gasoline	17.9	20.8
Diesel	25.1	28.7
Fuel Consumption, 10^6 BPD		
Total Fleet Cars		
Gasoline	1.00	0.78
Diesel	0.04	0.11
Total	1.04	0.89
Fleets of 10 or More		
Gasoline	0.39	0.30
Diesel	0.01	0.04
Total	0.40	0.34

Source: Ref. 5

TABLE L-3

TRUCK POPULATION AND FUEL CONSUMPTION

TRUCK CATEGORY	POPULATION x 10^6		AVG. TRAVEL	FUEL CONSUMPTION (bbl/d x 10^6)	
Total	1977	1985	Per Truck, mi/yr	1977	1985
Gasoline	25.174	34.2	-	1.53	1.63
Diesel	0.945	3.9	-	0.61	1.25
Other	0.094	-	-	-	-
	26.213	38.1	11,920	2.14	2.88
Fleet					
Gasoline	2.63	2.96	-	0.27	0.25
Diesel	0.53	1.23	-	0.39	0.77
Other	0.02	-	-	-	-
	3.18	4.19	20,500	0.66	1.02

Source: Ref. 5

TABLE L-4

BUS FLEETS IN 1981

Bus Type	Number, Thousands			Average Travel Per Vehicle			Average Fuel Economy, MPG	Fuel Consumption Thousand (mm)		Gal/yr
	Gasoline	Diesel	Total	Annual, x 1000 Mi	Daily, Mi 5 Days/Wk	Daily, Mi 7 Days/wk		Gasoline	Diesel	Total
Transit	1	52	53	30.9	118	85	3.8	9	422	431
Intercity	0	20	20	53.6	206	147	6.0	-	180	180
School/Non-Revenue										
Private	145	0	145	7.5	29	21	7.4	148	-	148
Public	254	0	254	7.5	29	21		259	-	259
Total/Average	400	72	472	12.1	46	33		416	602 (66,400 BPD)	1018

Source: Ref. 5

They represent approximately 50 percent of the passenger car fleet population. Daily rental cars are in many cases not refueled by the rental agency when distances traveled are large. Rental agencies would convert vehicles based on the type of vehicle use (short or long haul). Passenger car fleets between 4 and 9 cars would not be as attractive for conversion as the larger fleet sizes. Conversion of all fleet types will be constrained by the aforementioned potential bottlenecks of skilled mechanics and available cylinders, compressors, carburetor adaptors and possible proprietary, foreign regulators. Therefore, the most optimistic penetration factor assumed is 80 percent. Based on use patterns discussed above, much lower penetrations are assumed for passenger cars.

A significant segment of the passenger car gasoline market, namely, the commuter car has not been included in the fleet estimate. With large company ownership of commuter vehicles, which is a reality today, this type of vehicle can be considered in the fleet category because it returns to a home base on a regular basis. On the average, a commuter travels between 10 and 30 miles one way to work which would require between 1 and 3 refills per week. CNG conversion of commuter vehicles would likely follow the other fleet conversions and its effect may only begin to be felt in the 5-year oil replacement period. For that reason its potential has not been included.

The total estimated gasoline replacement by CNG vehicles is 393,400 bbl/d. Assuming equivalent fuel efficiency in vehicle operation this translates to 1.044 TCF of natural gas consumption per year or an oil replacement of 375,000 boe/d.

The current estimate of 20,000 to 30,000 CNG vehicles in the U.S. translates to approximately 1600 to 2400 boe/d current displacement. If CNG vehicles grow at twice the rate as the fleet vehicle population, by 1985 the increased oil displacement is insignificant (100 boe/d). Even using the AGA prediction[23] of 200,000 CNG vehicles by 1985, the oil displacement becomes only 14,000 boe/d. In order to achieve the proposed more than 150 fold increase (2,400 to 375,000 boe/d) in oil displacement will require largely expanded manufacturing capability of some components and an intensive training program for automobile mechanics. The lead time for implementation will depend on the ability to provide the potentially critical components such as cylinders and compressors in a short period of time. Should gaseous fuels for vehicles be considered an attractive oil replacement option, these potential bottlenecks will require further evaluation.

TABLE I-5

GASOLINE REPLACEMENT POTENTIAL FROM CNG CONVERSION OF FLEET VEHICLES

Fleet Type	Gasoline Consumption (bbl/d)	No. of Vehicles x 1000	CNG Usage Factor (%)	Conversion Market Penetration Factor %	No. of Vehicles x (MM)	Gasoline Displacement (bbl/d)
Passenger Car						
10 or more vehicles	300,000	4.95	95	35	1.65	99,800
4 to 9 vehicles	480,000	7.99	95	15	1.14	68,400
Truck (6 or more)	268,000	2.96	95	80	2.25	204,700
Bus	27,000	.4	95	80	.30	20,500
	1,075,000	16.30			5.34	393,400

CNG and LPG conversions of large numbers of vehicles are both dependent upon the availability of natural gas since the additional LPG required for vehicles is assumed to be derived predominantly from natural gas processing plants. The availability of the required natural gas for CNG conversions is feasible as discussed in Appendix O, where a scenario that provides an additional 2 TCF per year over current natural gas usage is presented.

Since LPG can be provided to private automobiles in LPG filling stations, its oil replacement potential for the private automobile market is dependent on the additional available LPG and the ability to increase the capacity of the LPG station network by number and size of stations. LPG use can also be increased by expanding the currently large number of LPG fleet vehicles. The additional 2 TCF of natural gas production per year will provide an additional 0.07 quads of LPG for vehicles per year based on the following:

a. 60 percent of the natural gas plant liquids (NGPL) is LPG.[25]

b. 76 percent of the LPG provided is suitable for vehicle fuel.

c. In 1981 NGPL production was 11.4 percent of total natural gas production on an energy basis.[8] Newly discovered deep or other gas may not be as rich in NGPL, thus, a future NGPL production of 8 percent is more likely.

Present LPG vehicles in the U.S.A., which conservatively number 1.5×10^6[19], consume approximately 0.14 quads of LPG annually mostly in fleet vehicles.[3] If all the additional LPG available from additional natural gas production were used in vehicles and vehicle fuel consumption occurred at current annual rates per vehicle, approximately another 0.8×10^6 additional vehicles could be powered by LPG. As a check, 1.5×10^6 vehicles using 0.14 quads of fuel converts to each vehicle traveling 15,000 miles per year at an efficiency of 20 MPG of gasoline, which is reasonable for fleet vehicles. In private car use with fewer miles traveled and future anticipated increases in fuel economy, perhaps another 0.4×10^6 above the 0.8×10^6 vehicles could be powered by LPG.

There are currently 25 domestic and foreign LPG conversion kit manufacturers but the bulk of the equipment is provided by 4 large domestic and 2 large foreign suppliers.[19] Since current equipment capabilities can provide conversion equipment for 1/2 million automobiles per year[19]

manufacturing capability is adequate to convert all 0.8 to 1.2 x 10^6 vehicles to LPG in the five year period.

As shown in Table L-5, the oil replacement potential of CNG is based on conversion of approximately 5 million vehicles. Since fleets are the only vehicle type that CNG can reasonably power on a large scale and to obtain maximum oil replacement, it makes sense to leave the fleet area to CNG and examine the ability to provide LPG to the private automobile market. It is estimated that there are approximately 11,500 locations at present in the U.S.A. that sell LPG for drive-in public use.[19] This compares to approximately 200,000 gasoline service stations in the U.S.A. in 1977.[20] There are an additional 25,000 LPG retail outlets that do not serve the vehicle market[19] but which could reasonably be modified to fuel vehicles in a crisis situation. The existing LPG vehicle service stations are grossly underutilized in terms of the amount of LPG sold compared to the gasoline service stations.[19] It is, therefore, reasonable to postulate that the existing 11,500 vehicle service stations with the additional 25,000 retail outlets converted to serve the vehicle market, could provide LPG refueling capability for millions of vehicles. The ability to deliver LPG to these facilities might present the most difficult bottleneck and would require further investigation if LPG were chosen as a major contributor to oil replacement.

Assuming LPG vehicles operate at the same fuel efficiency as operation on gasoline, the 0.07 quads of LPG translates to an oil replacement of 35,000 boe/d.

4. Costs

For CNG fleet vehicle conversions, it is currently estimated that it costs $2300-3600 per vehicle including costs associated with pumping and storage, installation and training of mechanics.[1,2,4,13,21] This includes fleets from 4 vehicles to hundreds of vehicles with the wide cost range due to differences in system compressor, storage and filling capacities as well as system sophistication. As shown in Table L-5, 5.34 x 10^6 vehicles are postulated for conversion to CNG powering. At an oil replacement of 375,000 boe/d, CNG conversions can be made for an investment cost of 12.3 to 19.2 billion dollars or 33,000 to 51,000 dollars per barrel per day.

The cost for a home installation with slow fill overnight has been estimated[21] as $6600 for one vehicle, $8200 for two vehicles. For an individual investment this cost appears to be prohibitive, but may be more attractive for the

multiple-commuter type vehicle. This vehicle market has not been included in the estimate of total vehicles for CNG conversion since it most likely follows the fleet market and will not be significant in the five-year period. For a CNG home installation assuming an average vehicle characteristic of 10,000 miles/year at a fuel efficiency of 18 mpg the oil replacement is 0.0346 and 0.0692 boe/d for 1 and 2 vehicles, respectively. This results in an investment of 118,500 to 190,700 dollars per barrel per day. This cost is significantly higher than that for CNG fleet vehicle conversion and thus, has not been considered in the estimate of total vehicles for CNG conversion in the 5-year period.

In order to serve the private vehicle, a network of CNG refueling stations would have to be constructed. One such refueling station in Canada recently cost $300,000.[4] This cost can be verified by proposing the following conditions for a public refueling station:

a. Average CNG vehicle refueling of 7 gallons of gasoline equivalent (720 scf of natural gas).

b. Largest domestically marketed CNG compressor capacity - 100 scfm with cost of $70,000.[5]

Based on the above, 3 compressors totalling $210,000 would be required for a 2.5 minute refueling time. In order to refuel more than one vehicle at busy times, storage cascades containing 3600 psig CNG would be required. The cost of storage cascades, regulators, nozzles, metering, construction, etc. can easily account for the balance $90,000 as verification of the validity of the $300,000 cost for a CNG refueling station.

With the approximate 100 million motor vehicles served by 200,000 gasoline refueling stations, it is prudent to expect that at least 10 percent of the refueling stations must have CNG capabilities to serve 5 to 10 million CNG vehicles. At $300,000 per station this translates to a total cost of 6 billion dollars. Using average private vehicle estimates of 10,000 miles/year at an efficiency of 18 mpg and $1500 per vehicle conversion results in a total cost of 13.5 to 21 billion dollars including refueling stations with an oil replacement of 172,000 to 345,000 boe/d. These capital costs and oil replacements translate to an investment of 60,000 to 78,500 dollars per barrel per day, higher than that for fleet CNG conversions. Similar to the commuter market, the private automobile CNG market refueled in public stations has not been included in our estimate of total vehicles for CNG conversion since it most likely follows the fleet market and will not be significant in the five-year period.

For LPG use as vehicle fuel it is reasonable to propose both fleet and private vehicle conversions since an LPG distribution network exists. For private vehicles, conversion costs are $1000-1500 per vehicle.[15] For 0.8 to 1.2 x 10^6 vehicles with an oil replacement of 35,000 bbl/d this translates to 0.8 to 1.8 billion dollars or 23,000 to 52,000 dollars per barrel per day. The capital cost for LPG storage and pumping in fleet applications is generally borne by the LPG dealer and the equipment is either leased to the fleet operator or included as part of the fuel cost. Some aggressive LPG dealers in the past have borne the cost of both vehicle conversions and LPG filling stations in order to sell LPG.[19]

In order to compare the product cost of each oil replacement technology in dollars per barrel of oil equivalent ($/boe), it is necessary to determine the three constituents of this cost: fixed charges, fuel charges and operating and maintenance (O&M) charges. Fixed charges are those costs associated with the capital investment incurred by the investor in the technology, i.e., interest on debt, return on equity, income taxes, depreciation, property taxes and insurance. These components form the basis of the fixed charge rate and their individual contribution will vary from one technology to another because of differing borrowing rates, required returns on equity, debt/equity ratios, tax treatments, depreciation schedules, etc. For simplicity of comparison, a fixed charge rate of 20 percent is assumed for all oil replacement technologies with capital costs and oil replacement occurring overnight. For CNG vehicles the capital investment of 12.3 to 19.2 billion dollars to replace 375,000 boe/d results in fixed charge of 18.1 to 28.9 $/boe.

The O&M costs for CNG vehicles are those over and above that for operating the vehicles on gasoline. These O&M costs include programmed replacement of equipment, parts replacement and electrical costs for compressing the natural gas.[2] Programmed replacement costs are those for removing the equipment from vehicles when traded or sold and installing the equipment in the replacement vehicles. These replacement costs will obviously not be incurred on the initial vehicle but have been included in our overnight cost since the cost will be incurred for most of the equipment life, e.g., 13 out of 15 years. Labor for equipment removal is estimated at 4 hours and reinstallation in replacement vehicles at 8 hours. At $15 per hour for labor the cost is $180 per vehicle. It is assumed that the average fleet vehicle is operated for 2 years and this factor becomes $90 per vehicle-year. Based on manufacturer information parts replacement is estimated at $33 per vehicle-year. An average size compressor for natural gas with a 11 kW motor will

process 17 scfm of natural gas.[13] Using the passenger car fleet averages of 20.8 mpg fuel efficiency and 23,400 miles per year[5], an assumed equivalent fuel efficiency with CNG powering and as electricity cost of 0.06$/kW-hr the electrical costs for compressing natural gas are $88 per vehicle year. The total O&M cost for CNG totals $211 per vehicle-year. As shown in Table L-5, 5.34 x 10^6 CNG vehicles will save 375,000 boe/d which translates to 25.5 boe saving per vehicle-year. Thus, the O&M portion of the product cost becomes 8.3 $/boe.

Using the cost of natural gas after the oil disruption of $10/MMBtu (see Appendix 0), the fuel cost component of the product cost is 55 $/boe. Thus, the total cost of converting gasoline powered vehicles to CNG on an oil replacement product cost basis is 81.3 to 91.3 $/boe.

The same product cost evaluation can be performed for LPG vehicles. The capital investment of 0.8 to 1.8 billion dollars to replace 35,000 boe/d results in a fixed charge of 12.6 to 28.5 $/boe. Since the O&M costs will not include any electricity costs for operating compressors and it can be assumed that the programmed equipment replacement and parts replacements costs will be the same as for CNG vehicles, the O&M cost for LPG vehicles is $133 per vehicle-year. The 0.8 to 1.2 x 10^6 vehicles converted to LPG powering replace 35,000 boe/d resulting in 10.5 to 17 boe saved per vehicle-year, which translates to an O&M factor of 7.8 to 12.7 $/boe. Using the current average national retail costs of LPG for vehicles of $0.8/gal[24], the fuel cost component of the product cost is 53$/boe. Thus, the cost for LPG vehicle conversions on an oil replacement product cost basis is 73.4 to 94.2 $/boe.

At current natural gas and gasoline price levels with various business-as-usual fuel escalation rates, paybacks as computed by simple analysis or discounted cash flow analysis for CNG conversions have been estimated[2,5,23]9d as one to four years. Based on these analyses the AGA is predicting 200,000 natural gas powered vehicles in the USA by 1985.[23]

Under the crisis scenario of a sudden disruption in oil supply with the price of gasoline soaring the payback for converting fleet vehicles may be on the order of months. The same is expected for LPG vehicle conversions. Thus, it should not be necessary for the federal or state governments to offer incentive for vehicle conversions since the free economic market will dictate them.

5. Non-institutional Constraints

The following are the potential non-institutional constraints to rapid deployment of CNG vehicle conversions:

a. Availability of mechanics sufficiently trained and skilled for installation and maintenance of equipment.

b. Sufficient manufacturing capability for compressors, cylinders, proprietary regulators, etc.

c. Loss of engine power of up to 15 percent.

d. Availability of fuel is dependent upon increased natural gas production.

e. Perception that gaseous fueled vehicles are less safe than gasoline fueled ones in an accident situation.

f. With motor driven compressors the energy expanded at the power plant to drive the motor for compression of the natural gas is about 9 to 12 percent of the energy content of the compressed gas depending on compressor size and gas supply pressure and composition.

g. The need to return to a central refueling station.

Except for the last two, all of the above apply to LPG vehicles as well. The potential bottlenecks are not expected to be as great with LPG, however, since the technology is more mature in terms of longevity, number of operating vehicles and current manufacturing capability.

6. Institutional and Regulatory Constraints

The following are the potential institutional and regulatory constraints to rapid deployment of CNG and LPG vehicle conversions:

a. Conflicts with car warrantees.

b. Highway tunnel and bridge prohibitions.

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M. ELECTRICITY IN TRANSPORTATION

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M-1 Series and Parallel Hybrid Electric Vehicles

1. Description

Electric vehicles (EV's) provide a means of replacing oil consumption through the use of a currently abundant resource, electricity, provided petroleum is not the fuel source of the generated electricity. The utility industry has twice as much reserve generating capacity as the traditional, safe margin back-up of 15 to 20 percent. Despite cancellations and postponements of new power plants, the nation has avoided the power shortages previously predicted for the beginning of this decade. Power plants that are otherwise idle, especially late at night when demand is low, are adequate in capacity to recharge millions of EV's. For almost all regions of the nation EV's can aid in the leveling of utility loads without requiring additional base-load capacity.

Batteries are the weak link in widespread acceptance of EV's. Storage batteries in commercially sold EV's are costly, bulky, require regular care and maintenance, limited in energy density (producing limited driving range) and power density (providing limited acceleration), require 8 to 10 hours to recharge and require replacement several times during vehicle life.[1, 10] Typically batteries account for one-third of the weight of an EV with EV conversions weighing 40 to 50 percent more than the conventional base vehicle.

Commercially available EV's are equipped with regenerative braking systems. When the driver applies pressure on the foot brake, a controller causes the regenerative system to perform motor braking and recovers this energy and returns it to the battery pack. Generally, when the vehicle speed drops below 20 mph, regeneration ceases and the mechanical brakes are used for stopping. Regenerative braking has been shown to increase vehicle battery range by approximately 4 percent.[8]

Commercially acceptable batteries require simultaneous improvements in energy density, power density, life and cost. However, the DOE program for EV research, design and development is being phased out. EV battery development status is summarized below according to the time frame of likely commercialization[4] assuming R&D emphasis is resumed.

a. Mid-1980's Technology

After it was determined that 95 percent of the round trips made by American motorists are less than 100 miles long, an EV battery range goal of 100 miles was established by DOE, which required an energy density of 56 Wh/kg. An acceleration goal of 0 to 30 mph in eight

seconds was established, requiring a power density of 104 W/kg. A life of 80,000 miles or 800 cycles, and a cost of $2,100 ($70/kWh) were also established as goals. Battery candidates that offer promise of delivering these characteristics by the mid-1980's include lead-acid, nickel-iron, nickel-zinc, and zinc-chloride.

1) Lead-acid

A 36 percent improvement in the energy density, from 30 to 41 Wh/kg, has been achieved by using plastic composite grids for the electrodes, improving the electrode shape (the height to width ratio), and increasing electrode material utilization. Further improvements in energy density will require additional basic changes in the electrodes to permit significantly higher utilization of the positive plate active material. A 150 percent improvement in cycle life, from 240 to 600 cycles, has been achieved through the use of improved electrode retainers, separator systems, and an electrolyte pumping system that avoids concentration gradients.

2) Nickel-iron

Major program emphasis is on reducing the weight of the nickel electrode without drastically effecting the life of the system. This will not only improve the energy density, but will also reduce the cost of the system, which is estimated to be at present at least twice that of lead-acid. Currently, improvements in the nickel electrodes are being sought by substituting steel wool for sintered nickel current collectors, and by increasing the utilization of the nickel. Cycle life of more than 800 cycles in individual cells using expensive sintered electrodes has been demonstrated. Therefore, the projected cycle life of 1200 for this system seems to be well within reach.

3) Nickel-zinc

This system has long demonstrated both good energy and power density. However, the classic problem of short cycle life for zinc alkaline systems, precipitated by the high solubility of zinc in the alkaline electrolyte, still has not been satisfactorily resolved. This high solubility of zinc is believed to cause early loss of capacity because of shape change and densification of the

electrode; it is also believed to be responsible for the formation of zinc dendrites, which result in electrode shorting. Some progress in the cycle life problem has been made through improvements in separators and electrolyte additives.

4) Zinc-Chloride

This system offers the promise of good specific energy and cycle life at a reasonable cost. While long cycle life, 1500 cycles, has been demonstrated for an electrode stack, it has not been verified as yet for a complete battery system. Both the demonstration of cycle life and improvement in the energy density from 65 Wh/kg (at present) to 80 Wh/kg (goal) will be dependent on resolving chemical engineering problems associated with heat exchangers, precipitators, pumps, etc.

b. Early 1990's Technology

A high temperature (450 C) lithium-iron sulfide system may be developed in this time period. Such a battery offers promise for a 150 mile range, with up to a 225 mile range assuming a 50 percent rapid recharge capability. Steady progress is reported in both energy density, from 69 Wh/kg in 1979 to 80 Wh/kg in 1981, and in cycle life, from 260 cycles in 1979 to 362 cycles in 1981. In order to achieve the early 1990's goals of 90 Wh/kg and 800 cycles at reasonable cost, continued improvements will be required in reducing the positive electrode swelling, elimination of capacity fade, reduction in the weight of cell components, and reduction in separator costs. Progress in increasing cycle life is being made as a result of improvements in electrode composition, and in the ratio of negative to positive active material.

Table M-1 summarizes the performance of an advanced EV with mid-1980's and early 1990's battery technologies. The current (1981) projections are extrapolations of present-day cell technology into full size batteries; the second case projections are based on the assumption that program goals are realized.

TABLE M-1

PROJECTED PERFORMANCE OF AN ADVANCED ELECTRIC VEHICLE

	Pb-A(a)	Pb-A(b)	Ni-Fe	Ni-Zn	Zn-Cl	Li-FeS
Current (1981)						
Range (mi.)	54	74	86	123	117	146
Life (mi.x 1,000)	13	44	67	22	2	53
Program Success						
Range (mi.)	54	90	108	126	144	225
Life (mi.x 1,000)	13	72	130	101	216	138

Note: Pb-A(a) are commerical units; PbA(b) are improved systems.

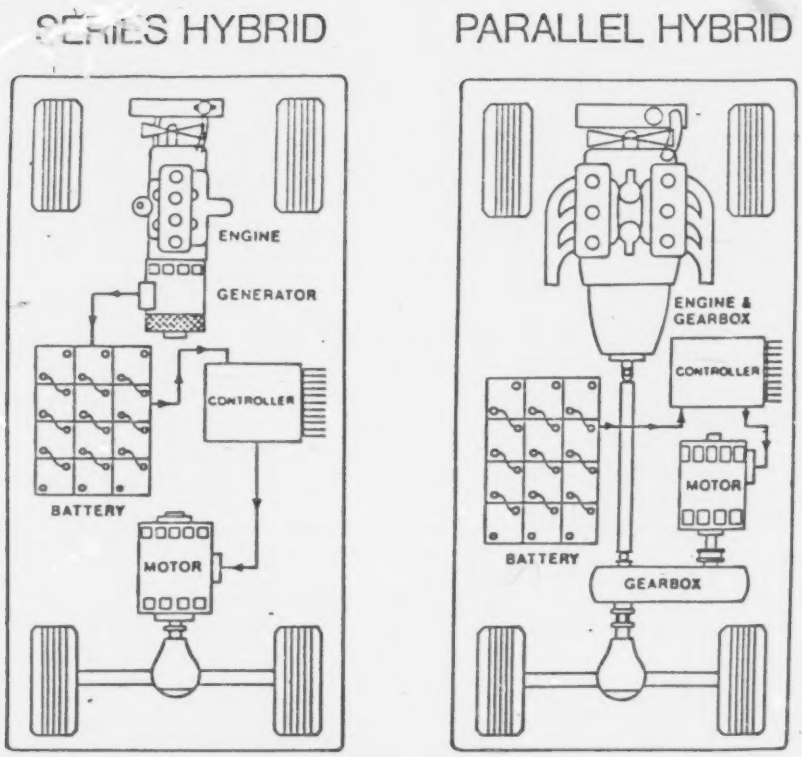
c. Mid-1990's Technology

Aluminum-air and iron-air battery systems are being developed. The aluminum-air system is being developed as a mechanically rechargeable battery (not electrical) that will be competitive in range with today's heat-engined vehicles (250 miles and more before aluminum plate replacement). During 1980, scale-up from laboratory size cell (50 cm^2) to full-size (100 cm^2) was accomplished with no degradation in performance. Future program emphasis should concentrate on building and testing full-size multicell stacks and on designing the mechanically replaceable aluminum plates. The iron-air system is an ambient temperature electrically rechargeable system which offers promise of a low-cost battery for a 150-mile EV. Program emphasis at the current time is on increasing the cycle life of the rechargeable air electrode, from 200 to 800 cycles, in a design that is economical to manufacture.

The lead-acid battery is the near-term commercial power system for EV's. The lead-acid battery has several inherent characteristics that limit its attractiveness for vehicle applications. Among these characteristics is the low ratio of power output to battery weight, poor efficiency at high current rates and reduced cycle lifetime when subjected to high current service. Each of these undesirable traits is mitigated when the battery is protected from demands for high power or current. This is accomplished with hybrid vehicles that provide another power source in addition to the battery. For passenger vehicles, hybrids can include a gasoline engine, a mechanical flywheel, compressed air or another battery.[11, 12]

There are two types of gasoline engine hybrids, series and parallel as shown in Figures M-1. In a series hybrid vehicle, the engine drives a generator which charges the battery; in the parallel hybrid, the engine can be directly coupled to the wheels. Within these two groups there are many permutations. Since this type of hybrid utilizes gasoline and is not in widespread commercial use, it is not considered further in our oil replacement analysis.

A mechanical flywheel hybrid is another approach to reducing the peak power demanded from a battery. In this approach the battery is used to provide the energy to spin the flywheel and maintain it at speed during periods of less than high power demand. The flywheel also recovers and stores vehicle kinetic energy through regenerative braking. During periods of high vehicle power demand, i.e., acceleration, the energy stored in the flywheel is used. This reduces the high current demands on the battery. A battery hybrid system utilizes a zinc-bromine battery in place of the mechanical flywheel to protect the conventional lead-acid battery from high current demands. The zinc-bromine is connected in parallel with the lead-acid, both during charging and discharging when hybrid system operation is desired. Neither a flywheel hybrid nor a battery hybrid EV is available commercially.



The schematic shows the difference between a series and parallel hybrid. In the series hybrid (left), the engine is used to drive a generator which charges the battery; in the parallel hybrid, the engine can be directly coupled to the wheels.

Figure M-1

Series and Parallel Hybrid Electric Vehicles

Source: Ref. 11

2. Commercialization Assessment

Over 7000 EV passenger cars, trucks and vans have been produced in the last decade in the USA, many by companies no longer in business.[13] Including EV vehicles produced by hobbyists, the number exceeds 9000. These totals do not include the large production of other types of EV's including golf cars, forklifts, bikes, etc., whose 1982 USA estimated production totals nearly 70,000.

This year has been a very bad one in terms of on-the-road EV sales [14, 15] reflecting both the general downtown in automobile sales and the public's lack of acceptance of EV's. Although there are 25 passenger car (2000 lbs or more) manufacturers, 32 truck manufacturers, and 17 van manufacturers in the world,[16] there is not a large mass production EV capability.

In order to achieve the required several hundred thousand EV output per year to achieve major oil displacement, it will require commitment of billions of dollars by major automobile manufacturers in terms of tooling and new or modified factory assembly lines. The lead-acid battery is the only one used in commercially sold EV's.[17] Based on the lack of current commercial sales success and the drastic reduction in R&D support by DOE it is anticipated that the lead-acid battery, although improved, will remain as the battery used in commercially sold EV's during the 1985 to 1990 time frame.

Based on an examination of manufacturers' claims [3, 4, 9, 10, 18], comparison to actual test results along with degradation of battery performance with time [8], and an anticipated modest improvement in EV technology, a vehicle route of 50 miles with a battery life of 20,000 miles (2 years) is used as the baseline for EV performance in the 1985 to 1990 time frame.

3. Oil Replacement Potential

Electric vehicles can be sold potentially to the second-car, commuter and fleet passenger car market where daily driving range is less than 50 miles and a compact to subcompact car is sufficient for the payload. The other major area where electric vehicle performance is sufficient is the light-truck fleet market. Electric vehicles match urban/suburban driving requirements of these markets which very often inefficiently use gasoline by virtue of stop-and-go driving, short trips and rush-hour congestion while contributing significantly to air pollution.

The electric vehicle passenger car potential can be estimated by examining automobile sales and use statistics. In the private automobile market it is reasonable to assume that the American household requires one unlimited-range car. This leaves the second car market which is substantial since 45 percent of the households with cars in 1976 had 2 or more cars.[19] In 1975 34 percent of new cars sold were compacts or subcompacts [19] and it is assumed that today this amount has risen to 50 percent. Also in 1975 it can be inferred from statistics that 76 percent of all subcompact and compact cars were registered within the metropolitan areas.[19] Using 10 million new car sales per year in the USA as a baseline, the new compact or subcompact cars sold in the metropolitan areas as second cars number approximately 1.67 million cars per year. It is prudent to assume that at best only 50 percent of this market can be penetrated by electric vehicles and considering tooling up time required by the automobile industry to achieve mass production, the most optimistic total of additional EV passenger cars is 2 million at the end of the 1985 to 1990 period. Assuming 10,000 miles per year for each car and a gasoline efficiency of the car replaced by the EV of 40 mpg, the oil replacement is 32,000 boe/d. It is assumed that commuter cars are included in the population of vehicles categorized as second-cars.

The fleet passenger market has been characterized in Appendix L. Only utility fleets average less than 50 miles per day having a total of 162,000 vehicles in fleet sizes of ten or more in 1981. It is assumed that most utility fleets fall into the 10 or more vehicle category. If 100 percent of this market were penetrated by EV's, despite using the low fuel economy of 16 mpg of utility fleets in 1981 only results in an oil displacement of approximately 8000 boe/d. With anticipated higher fuel efficiencies in the 1985-1990 time frame this savings is only 4000 boe/d.

Light-truck fleet vehicles numbered 1.6 million, consumed 1.8 billion gallons of fuel in 1977 and travelled an average of 14,300 miles/year.[20] Projections for 1985 estimate 2.5 million fleet vehicles with light trucks averaging 15.1 mpg. Historically, light trucks in fleets that have a driving range requirement under 50 miles per day represent only 13.65 percent of light-truck fleet vehicles.[19] Assuming a light truck fleet vehicle is replaced every 7 years (approximately 100,000 miles) and a 100 percent sales penetration by light-truck EV's in the under 50-mile range market, approximately 120,000 light-truck fleet vehicles can be EV's by 1990 considering the tooling-up time required by the vehicle industry to achieve mass production. With anticipated light-truck fuel economy in the 1985-1990 time

frame of 30 mpg this results in an oil displacement of approximately 3,500 boe/d.

Thus, the total oil displacement with EV's in the passenger car and light-truck markets is 39,500 boe/d. Current oil displacement by EV's at best is only 100 to 150 boe/d. The 39,500 boe/d displacement is based on a total of approximately 2.3 million EV's by 1990 which is very optimistic considering the total of 7000 EV's produced in the USA between 1972 and today.

4. Cost

At present EV's cost more than comparably sized vehicles powered by internal combustion engines. There are compacts and subcompacts, four-doors, vans, station wagons, pickup trucks and even sports cars. Prices range from $6000 to $30,000 per vehicle.[1] Certainly much of this added cost is based on the lack of mass production at rates comparable to conventional vehicles.

Since approximately 94 percent of the 2.3 million EV's projected as potentially part of the vehicle population by 1990 as a result of a major oil disruption are compact and subcompact cars, the cost premium for EV's is based on this class of vehicle. One of the largest manufacturers of passenger car EV's in the USA, Jet Industries, sells a converted Ford Escort, which is a two-door, four passenger hatchback. The vehicle is renamed the Electrica and sells for $11,295 (list price) exclusive of tax, title and destination charges.[21] The Ford Escort with comparable options sells for $5629 (list price) exclusive of tax, title and destination charge.[22] This $5656 differential is due to added costs for batteries and electric controls as well as economies associated with mass production. It is assumed that at a several hundred thousand EV production rate per year, EV's will achieve comparable mass production economies and that the cost differential will be based on battery, controls and other EV add-ons vs. the internal combustion engine (ICE) and its associated equipment. It has been estimated that vehicle manufacturers would have to commit $2 to 4 billion to mass produce EV's in the range of 100,000 per year.[23] A commitment of $4-8 billion or more amortized over several years would add significantly to EV cost. Based on this the EV's are estimated to cost $2500 to 3500 (1982 $) more than comparable ICE vehicles. Thus, to replace 52,000 boe/d will require an investment of 5.7 to 8.1 billion dollars over and above the cost of comparable ICE vehicles or 144,000 to 205,000 dollars per barrel per day.

In order to determine the equivalent oil product cost in $/boe the fixed charges, fuel charges and O&M charges are determined. As with the other oil replacement technologies, a fixed charge rate of 20 percent is assumed with oil replacement and capital investment occuring overnight. The fixed charge for EV's is 79 to 112 $/boe.

The fuel cost consists of the electricity cost for battery charging. Energy consumption for lead-acid batteries in compact and subcompact cars ranges from 0.16 to 0.5 kWh/mile depending on vehicle size and battery age.[4, 5] Energy consumption in vehicles with higher payload such as light trucks fleets is greater at 0.6 to 1.8 kWh/mile.[5-8] At $.06/kWh this translates to 180 to 300 $/vehicle-year electric cost for compact and subcompact cars. This fuel expense saves 39,500 boe/d in 2.3×10^6 vehicles which results in a fuel charge of 29 to 48 $/boe.

Recent evidence [8] has concluded that maintenance and repair costs for EV's are higher than those of ICE vehicles due to design deficiencies and maintenance requirements of the battery systems. For this assessment it is assumed that except for battery replacement EV O&M will be improved by the 1985 to 1990 time frame such that it is the same as for an ICE vehicle. Battery replacement frequency is dependent upon the care taken in periodic battery maintenance, equalization and load testing as well as operating temperatures and terrain conditions. Battery life for current compact and subcompact EV's is advertised at 12,000 to 30,000 miles or 2 to 3 years.[2, 3, 9, 10] It is assumed that in the 1985-1990 time frame the batteries will last on the average of 20,000 miles (2 years). Battery replacement cost for the small passenger car vehicle has been estimated at approximately $1500.[5, 13] This can be verified by using the energy density of 41 to 42 Wh/kg of improved lead acid batteries [3, 4] and 1982 production costs of 60 to 107 $/kWh of commercial lead-acid batteries.[24] A typical compact EV today has a battery weight of 460 kg [10] which results in a battery production cost of $1100 to $2070. Adding markup and installation costs and assuming high production volume resulting in costs near the low end of the range, a battery replacement cost in a typical compact EV of $1500 (1982 $) is reasonable. With an average 2-year life this translates to $118/boe. Thus, the annual cost of EV's, on an oil replacement basis, is 226 to 278 $/boe (1982 $). This only includes the incremental cost above that of replacement ICE vehicles of comparable size.

A comparison of the operating cost of EV's vs. ICE vehicles can be made using recent detailed data from the EPRI/TVA Pilot Electric Vehicle Demonstration Project.[8] It was found

that for EV vans and buses the operating cost exclusive of battery replacement was 25.2 to 29.7 ¢/mile at an average energy use of 0.9 kWh/mile. For compact EV's the energy use is about 0.3 to 0.5 kWh/mile but the cost of electricity is higher on average than in the TVA area. The energy cost portion for a compact EV would be approximately 1.8 to 3¢/mile resulting in an operating cost of 23.2 to 29.3¢/mile. Since battery packs are larger and conditions more demanding for vans and buses than compact cars, it is reasonable to assume that maintenance costs will be less for compacts reducing the operating cost to 20 to 25¢/mile. Battery replacement adds 7.5¢/mile resulting in a total operation cost for compact EV's of 27.4 to 32.5¢/mile. The US DOT has recently estimated the cost of operation of compact ICE cars at 21.4¢/mile [25] of which approximately 4¢/mile is fuel cost. In the oil disruption scenario with gasoline prices sharply escalating, the operating costs of EV and current ICE vehicles would thus be comparable. With more fuel-efficient cars anticipated in the 1985-1990 time frame the ICE vehicles would be less expensive to operate.

5. Non-institutional Constraints

The non-institutional constraints on widespread use of EV's during a major oil disruption are:

a. Lack of a sufficient mass production capability.

b. Acceptance by the public of a limited range/limited acceleration vehicle.

c. Danger of explosions due to battery overcharging causing the evolution of sufficient hydrogen in a confined space. [26]

d. Although an environmental advantage, the silence of EV's during operation can pose a danger to pedestrians.

e. Vehicle space conditioning - cooling not feasible and heating for passenger comfort and defogging and defrosting of windshields only possible with combustion heaters that operate on gasoline, kerosene or propane.

f. In vehicle conversion the adequacy of the existing braking system to handle the additional weight must be addressed.

6. Institutional Constraints

The institutional constraints on widespread use of EV's during a major oil disruption are:

a. Mandated auto safety requirements are not written with EV design features in mind in the areas of transmissions, transmission braking effect, windshield defrosting and defogging, braking, headlamps, accelerator control, bumpers, etc. [27]

b. Road use tax on motor fuel. If this is extended to electricity used to operate vehicles, the cost to operate EV's will be increased.

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N. ENHANCED OIL RECOVERY

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1. Description

The recovery of oil by processes that produce higher oil displacement efficiencies than those obtained through the natural processes of gas and waterdrive is termed enhanced oil recovery (EOR). EOR is principally used for tertiary recovery, that is, after primary production from natural drive and secondary recovery generally from waterflooding are complete. However, EOR refers to any process or technique that overcomes the natural forces that impede recovery of oil, be it primary, secondary or tertiary.[1, 2, 3]. EOR allows primary production without passing through any secondary recovery period, for example, steam is being used to recover primary heavy oil. Thus, the term EOR does not necessarily identify tertiary recovery.

EOR methods can be grouped as follows:

a. Thermal - steam injections, in-situ combustion, hot waterflooding

b. Gas Flooding - carbon dioxide, inert gas, natural gas

c. Chemical Flooding - surfactant flooding, polymer augmented waterflooding, alkaline flooding

d. Novel Technologies - electrical methods, microbial EOR, oil mining.

The thermal techniques are used to recover heavy oil while the others are for light oil recovery. Most likely, future EOR will use a combination of these techniques, each designed to correct or overcome specific problems that have led to the entrapment of oil under specific reservoir conditions.

Reservoirs containing oil whose composition is such that under the conditions of recovery it is very viscous and difficult to produce can be stimulated by thermal recovery methods. In-situ combustion is the process in which the reservoir is heated as a result of oxidizing the heavier portions of the crude oil by injecting air until a sustaining oxidation or combustion occurs. This heats the reservoir and the oil becomes less viscous while simultaneously swelling the reservoir by the absorption of exhaust gases. Steam injection is the major thermal method. It is applied either continuously in which the heat from the steam warms the reservoir system thereby reducing the viscosity of the oil, or as a cyclic process by allowing the reservoir to "soak" and produce the "thinned" oil from the same well through which the steam was injected.

Carbon dioxide injection is an example of a gas flooding technique. Injected carbon dioxide becomes miscible with the reservoir crude oil under reservoir conditions which are approximately between 1,000 and 4,000 psi, and therefore, can theoretically effect 100 percent oil recovery in that part of the reservoir contacted by carbon dioxide. When injected under pressure, it causes the oil to swell and decrease its viscosity, so that it may be driven out by waterflooding (or nitrogen).

Of the techniques used for light oil recovery, carbon dioxide (CO_2) flooding has the best potential for the near future. While CO_2 flooding is inexpensive compared with chemical flooding, many times it is only marginally economical because the enormous amounts of required CO_2 are normally not readily available.

In the chemical flooding process, chemicals are injected to mobilize oil that cannot be displaced by water alone. The mechanism of this mobilization is related to numerous chemical and physical properties of the reservoir and injected fluids. Although process developers have developed "first-generation" chemicals that are capable of efficient oil displacement, significant improvements in the formulation, manufacture, and use of these chemicals are needed.

2. Commercialization Assessment

U.S. oil output via EOR is currently 375,000 bbl/day, roughly 4 to 5 percent of total production, which is up from the 333,000 bbl/day level in 1980.[4, 5, 6] Of this total over two-thirds is from heavy oils produced by steam recovery projects in California. Thermal recovery projects (steam and combustion) currently produce approximately 80 percent of the total enhanced oil with about 51 percent of the total number of active U.S. EOR projects. The corresponding production and project percentages for gas and chemical flooding are 19 percent and 18 percent, and 1 percent and 31 percent, respectively.

Not only in terms of production are the thermal recovery methods important but operators have more experience with such methods, especially steam, than any other method. For example, in one heavy oil field in California, primary production would have left 99 percent of the original oil in place (OOIP) in the ground. By injecting steam, recovery over the last 20 years has reached more than 38 percent of OOIP.[1] Thermal methods are expected in the near future to continue to contribute the majority of EOR production.

Because of the low primary/secondary recoveries in heavy oils, the thermal techniques have the highest recovery efficiencies, from 25 to 64 percent of the remaining oil in place.[2] Carbon dioxide flooding and chemical flooding have recovery efficiencies varying from 15 to 19 percent, and 4 to 43 percent, respectively.[2]

3. Oil Replacement Potential

To date, the U.S. has proven reserves of 450 billion barrels of OOIP from pre-1981 discoveries.[5, 6] As shown in Table N-1 the target for EOR methods is large for the pre-1981 discoveries - over 300 billion barrels.

The post-1980 crude oil discoveries through the year 2025 have been projected at 181 billion barrels.[7] The tertiary portion of this projection is 58 billion barrels. However, this additional amount will not contribute to the EOR output during the 1985 to 1990 time frame since tertiary reserves are not added until ten years after primary production starts.

After sudden oil disruption, the incentives to increase domestic oil production would be enormous and the amount of potential oil recovery by enhanced techniques would increase by virtue of the demand. Various estimates have been made of the additional oil that could be added to the existing recoverable reserves. These vary from 11 to 52 billion barrels.[5,6,10] It is unlikely that more than 51 billion barrels can be recovered under any economic conditions using current and foreseeable EOR technology.[10]

Estimates have been made of the daily output from EOR techniques under various economic scenarios.[7, 8, 10] These vary from 0.5 to 1.0 MMbbl/d in 1985 to 0.7 to 2.8 MMbbl/d in 1990. Since all of the injection fluids used in EOR escalate with energy cost, projected daily output does not necessarily increase drastically in the event of a sudden oil disruption.[2] The cost of CO_2 is dependent on the fuel cost to operate pipeline compressors for transport of CO_2 and the costs for energy intensive compressing of the CO_2 to liquid during cleanup in CO_2 manufacturing.[11] The adverse impact of increased energy costs on production via EOR techniques can be reduced when an alternate fuel such as coal is used for steam production.

TABLE N-1

ESTIMATED RESERVES FOR
ENHANCED OIL RECOVERY
(Pre-1981 Discoveries)

	Billion Barrels		
	Light Oil	Heavy Oil	Total
Original Oil in Place	350	100	450
Recovered to Date	-93	-25	-118
Recoverable Reserves (without EOR)	-27	-1	-28
EOR Target	230	74	304

Source: Refs. (5) and (6)

Based on current world oil supplies it is likely that the actual oil production via EOR in 1985 will be at the low end of the projected level, 0.5. to 0.6 MMbbl/d. With an 11 to 51 billion barrel potential resource to be recovered at this production rate, EOR of pre-1981 oil would proceed for approximately 50 to 280 years. Of course, this production is primarily needed to make up for the diminishing production of pre-1981 primary and secondary crude oil. Under the crisis situation, disregarding the equipment, energy and manpower constraints for the moment (see Section 5 below), the EOR reserve is sufficiently large enough to permit a susbtantial increase of the EOR production rate. For planning purposes and Phase II analysis, it is projected that EOR output would increase to 1.5 to 1.6 MMbbl/d by 1990, an increase of 1.0 MMbbl/d. This is a reasonable target against which potential constraints of implementation can be measured since it is near the midpoint of the 1990 projection for EOR production.

The increase in the projected EOR production rate would by necessity occur through EOR techniques that are the least energy intensive and can use nonpetroleum based fuels and feedstocks. In the manufacture of chemicals for EOR injection, significant amounts of petroleum and petroleum based products are used. [2] The most attractive candidates are steam injection from solid fuel-fired boilers and CO_2 injection. In addition to the inherent relationship of the cost of chemicals to petroleum prices, which discourages this technique in the petroleum price escalation scenario, there are many technical problems with chemical EOR techniques that will discourage appreciable recovery with these techniques until the 1990's.[8]

The 1.2 MMbbl/d business as usual projection for EOR in 1990 includes 600,000 bbl/d from thermal methods, 500,000 bbl/d from gas injection and 100,000 bbl/d from chemical projects. Others have projected as much as 800,000 bbl/ by gas flooding in 1991.[4] The additional EOR production of 1.0 MMbbl/d as a result of the oil disruption crisis could be achieved as 500,000 bbl/d by thermal methods and 500,000 to bbl/d by gas flooding.

With current oil-fired steam generators for steam injection EOR, about one barrel of crude oil is consumed to produce 3 barrels via EOR.[3] In the crisis situation with critical oil price and availability levels, solid fuels such as coal and petroleum coke will be used for steam production. Currently, there are several EOR projects using these fuels with fluidized bed combustion boilers.[9] Cogeneration is being employed in some to improve project revenue streams to offset the added capital cost for the solid fuel-fired systems and associated environmental add-ons.

4. Costs

The capital costs for EOR by steam flooding, as shown in Table N-2, are based on a typical 50 MMBtu/hr capacity steam generator. As shown, cost varies from 3,900 to 12,000 $/bbl/d for projects with oil/gas-fired boilers and 12,500 to 19,900 $/bbl/d for solid fuel-fired units. The large variation is due to the site specific depth of injection wells, which for future thermal EOR, is assumed to vary from 2000 to 5,000 feet. Drilling costs are 100 to 140 $/ft.

The cost of producing a barrel of oil by steam injection ranges from 27 to $35/bbl assuming the price of oil burned for generating the steam is $30/bbl.[2] This cost would rise drastically in the event of a sudden oil disruption. With coal- or petroleum coke-fired steam generation (instead of

oil-fired steam generation) the capital cost would rise by 4 to 5 times.[2] However, the lower cost of solid fuels can significantly overcome the impact of higher capital investment on product cost. Consequently, we have assumed that the cost for producing a barrel of oil by solid fuel steam injection is also in the $27 to $35/boe range.

The capital costs for EOR by CO_2 flooding are shown in Table N-3 for projects based on natural and manufactured CO_2. The natural CO_2 project is the one planned by Shell [16, 17] and represents a very large EOR project with a 500-mile pipeline from the CO_2 source in Colorado to the oil field in West Texas. This manufactured CO_2 project is representative in size of current production oil fields with CO_2 EOR [5].

For both projects the cost at the low end for CO_2 distribution and wells are representative of current well depths (approximately 5000 feet). Cost at the high end of the range represent future depths of 5,000 to 10,000 feet. The manufactured CO_2 plant cost at the low end of the cost range is for a 95-percent CO_2 byproduct, flue gas. The high end of the cost range is based on a 50-percent CO_2 flue gas, which requires extensive separation equipment. The pipeline cost is based on a 50-mile distance from the CO_2 plant to the oil field.

The current cost for producing a barrel of oil by carbon dioxide flooding from natural source CO_2 is estimated at $26 to $39/bbl.[2] (This includes natural source CO_2 at $12 to 16/bbl based on an overall CO_2 cost of $1.20/mcf comprising CO_2 procurement cost of $1.00 to 2.00/mcf and recycled CO_2 cost of $0.50 to 0.60/mcf.) Using manufactured CO_2 cost of $2.00-5.00/mcf[2] and similar recycling costs, the overall CO_2 cost is estimated at approximately $3.00/mcf, which brings the annual CO_2 cost to $30-39/bbl. Total annual cost of recovered oil with manufactured CO_2 injection is $44-62/bbl. These costs assume that the oil field is located within an "economic distance" from the source of carbon dioxide. The "economic distance" is defined[2] as 500 miles for natural source carbon dioxide and less than 50 miles for manufactured sources (owing to the cost of gas compression). It is possible that under the oil disruption scenario sufficient incentives would be present to justify carbon dioxide flooding beyond this "economic distance." This will result in added investment cost for pipelines and added cost of carbon dioxide, thus increasing the annual costs of oil recovered.

TABLE N-2

CAPITAL COST SUMMARY FOR
EOR BY STEAM FLOODING

	Cost in 1000$(*)	
	Oil/Gas-Fired	Solid Fuel-Fired
Boiler Capacity, MMBtu/hr	50	50
Capital Cost		
- Boiler including flue gas cleanup	600-800	5,000-6,000
- Piping, tanks, etc.	200-250	200-250
- Wells (9 to 10 injection wells per 50 MMBtu/hr unit) 2000 to 5000 feet deep	1,800-7,000	1,800-7,000
Total Capital Cost	2,600-8,050	7,000-13,250
EOR Production, bbl/d (**)	667	667
Capital Cost $/bbl/d	3,900-12,100	10,500-19,900

(*) References (14) and (15)

(**) Based on 75 lb/hr of steam capacity required per barrel of oil via EOR [3,10,12,13]. This is the recovery anticipated for future EOR projects. Since recovery is difficult to predict with certainty, capital costs per recovery rate may be higher for some projects.

TABLE N-3

CAPITAL COST SUMMARY FOR
EOR BY CO_2 FLOODING

	Cost in 1000$	
	Natural CO_2 [16 17]	Manufactured CO_2 [2 11]
CO_2 Injection from pipeline (*), CF/d	256-33 x 10^6	10-13 x 10^6
Capital Cost		
- CO_2 Plant	40,000(**)	4,000-16,000
- Pipeline	208,000(***)	10,000
- CO_2 Distribution and Injection Wells	260,000-400,000	10,000-15,00
Total Capital Cost	508,000-648,00	24,000-41,000
EOR Production, bbl/d	25,600	1,000
Capital Cost $/bbl/d	19,800-25,300	24,000-41,000

(*) Based on historical 10,000-13,000 CF/d injected CO_2 per barrel of oil recovered. Since recovery is difficult to predict with certainty, capital cost per recovery rate may be higher for some projects.

(**) Total CO_2 plant cost is \$330 x 10^6. The plant has a total 10 TCF resource of CO_2 of which 1.2 TCF will be used for the 25,600 bbl/d EOR project. Capital cost alotted is \$40 x 10^6 from (1.2/10) x (\$330 x 10^6).

(***) Total pipeline cost is \$625 x 10^6. The pipeline has a total capacity of 1 x 10^9 CF/d of which a maximum of 333 x 10^6 CF/d is for the 25,600 bbl/d for project. Capital cost alotted is \$208 x 10^6 from (333 x 10^6/1 x 10^9) x (\$625 x 10^6).

5. Non-institutional Constraints

The non-institutional constraints to acceleration of EOR production above that currently projected are as follows:

a. Technical mechanisms for EOR are complex and require an economic evaluation on a reservoir by reservoir basis. Results are difficult to predict with certainty and thus require that investors seek a high rate of return, which in turn increases the selling price of the recovered oil.

b. The heavy oil refining capacity on the west coast is limited and will constrain utilization of substantial increased quantities of heavy crude. Adequate transportation system will be required to alleviate this problem.

c. There is a close link between oil prices and the cost of injection fluids used in EOR.

d. Availability of steam generators, pollution control equipment and compressors for thermal EOR methods under accelerated conditions could create bottlenecks.

e. Proximity of carbon dioxide sources to oil fields could be a constraint.

f. EOR projects require several years from start of reservoir screening to commercial production.

6. Institutional and Regulatory Constraints

a. High financial transfers associated with the production of oil result in high product costs. The financial transfers include royalties, severence taxes, state/Federal income taxes and the windfall profits tax. Windfall profits tax would need to be reduced or eliminated. Royalties would have to be converted to lower fixed payments or a share of profit. EOR projects under any economic scenario must provide a return commensurate with the risk involved. Despite the tax break afforded EOR under the windfall profits tax, the tax bite nevertheless increases the risk of the projects.

b. Environmental regulations, particularly in California, severely limit the acceptable level of air pollutants from steam generators. The limits on NOx are particularly troublesome.

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0. INCREASED NATURAL GAS PRODUCTION, STORAGE AND DELIVERY

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0-1 Increased Gas Supplies from Various New Sources (TCF/yr)

1. Introduction

The short-fall of petroleum based energy postulated for this study ranges from 3 to 4 x 10^6 bbl oil/day.[1] Much of this could be compensated for by an increased production of natural gas (NG) by conventional drilling, unconventional extraction and increased imports.

The time frame for activities which will alleviate the effect of the short-fall is from 1985 to 1990.

The breakdown of petroleum usage anticipated for 1985 is summarized as follows[2]:

	bbl/day
Mobile engines	8.0 x 10^6
Stationary Uses - Distillate	1.0 x 10^6
Nontransport - Residual	1.5 x 10^6
Heat/Hot Water - Nonresidual	1.2 x 10^6
Other fuels	4.3 x 10^6
Total	16.0 x 10^6

2. Commercialization of Technology

a. Conventional drilling involves no untried technologies, and includes gas associated with oil production, and gas-only wells drilled to shallow and great depths.

b. Tight gas is NG found in either blanket or lenticular formations that have a very low permeability. The fracturing technology required is in current use with blanket formations. The technological problems associated with recovering gas from tight lenticular sands are considered more severe than recovery problems in blanket reservoirs. The problems of exploratory drilling to great depths and drilling in high temperature rocks for conventional gas are generally not encountered with tight gas exploration.

c. Coal bed gas can be found in coal seams lying below drainage. Two presently viable methods of extraction are:

1) Hydraulically stimulated vertical wells.

2) Unstimulated horizontal holes from vertical shafts.

d. Devonian shales are shales which have a high proportion of organic material, and, due to thermal effects, this organic material has been transformed to NG. Extraction is similar to the conventional drilling of wells. Advanced technology upgrades performance by means of well stimulation.

e. Geopressured brines are to be found in underground reservoirs containing hot salt water under pressure. They contain no free oil or gas but the brine is assumed to be saturated with NG. The technology is in the study phase. Development would consist of drilling and extracting the hot brine by natural flow. The geothermal energy could be converted to electricity and the methane extracted from the water. Although there are limited technical constraints to drilling and producing the gas, locating the sites[3], brine disposal, inadequate reservoir sizes and process economics are major problems.

f. Coal gasification involves the application of methanation chemistry to produce NG from coal. The technology for these plants has been in use for many years.

g. NG from biomass and wastes is obtained from land-based and marine environments. The technologies involve a variety of biological and thermal gasification processes, but many technological challenges remain before these concepts are proven feasible for broad commercialization.

3. Oil Replacement Potential

Estimates of future NG supplies vary widely. For 1990, the American Gas Association (AGA) has summarized the supply picture under four different national policy scenarios.[4] One scenario emphasizes U.S. sources only; one emphasizes North American sources; one mildly restricts the overseas gas supplies; and one assumes that natural gas will rapidly be made available to U.S. markets from sources throughout the world. Average and average maximum supply estimates for the four scenarios are 22.4 and 24.0 TCF/yr, respectively, representing increases of 2 and 3.6 TCF/yr over the 1981 level of gas supply.

For each scenario a high and low estimate are presented. The high estimate assumes vigorous technology growth encouraged by government and industry support and federal policy and

regulatory decisions in favor of increasing gas supplies. Under our scenario for major oil disruption, it is expected that the contribution from increased imports would be diminished based on high costs. Also, the projected supply of 0.7 TCF/yr in 1990 from coal gasification is considered overly optimistic by G&H. On the other hand, the projected supply from conventional and nonconventional domestic sources would be expected to increase assuming wellhead prices were allowed to increase above the current level.

Based on the above considerations, the average increase of 2 TCF/yr from the AGA analysis is selected for 1990. This proposed 2 TCF/yr increase over the 1981 supply will come from a variety of sources including additional conventional, nonconventional, and synthetics sources, and is equivalent to 1×10^6 bbl oil/day. Phase II of this study will identify the issues which could constrain this increased supply.

4. Cost

The AGA analysis[4] estimated the capital requirements to achieve the supply levels projected under the various national policy scenarios. The required capital investment of $208 billion is broken down as follows:

	1982 $ Billions 1982-85	1986-90
Exploration & Development	26.7	36.9
Utility & Pipeline Construction & Maintenance	27.2	34.0
Coal Gasification, Alaskan Gas Pipeline & LNG	38.8	44.0
	92.7	114.9

The differences between the gas supplied in 1981, and the 1990 projections for the self-sufficiency and the North American Focus policy scenarios, are shown in Table 0-1. Gas supplies in 1990 compared to 1981 from the lower 48 states conventional sources are expected to decrease from 19.3 to 15-17 TCF/yr[4]. As shown in Table 0-1, of this 15-17 TCF/yr, 0.5 to 1.0 TCF/yr are expected to come from new conventional sources in the lower 48 state. The other gas supply increases are based on Reference (4) except for the 0.3 TCF/yr for coal gasification which is reduced from the 0.7 TCF/yr level considered overly optimistic by G&H.

As shown in Table 0-1, the gas supply in 1990 from new sources varies from 3.5 to 6.8 TCF/yr. Based on the $208 billion capital investment anticipated by AGA, the cost of increased natural gas production, storage and delivery is approximately 60,000 to 120,000 $/boe/d.

Under the National Gas Policy Act approximate wellhead prices of $1.25/MCF for old gas (dedicated to pipelines before April 20, 1977), $3.00/MCF for new gas (as of April 20, 1977), $7.25/MCF for gas below 15,000 feet and for unconventional gas, and $5.00/MCF for imports and other category costs, result in an average residential price of $5.70/MCF (May 1982)[14,15]. The end-use price in 1985 without an oil disruption is dependent on the outcome of the current natural gas deregulation controversy and is the subject of much debate. Rather than attempt to predict if gas will be deregulated in 1985, a price of $10/MCF (or $55/boe-1982$), assigned for planning purposes, provides sufficient economic incentives for conservation, exploration, and production of additional conventional and unconventional gas.

TABLE 0-1

INCREASED GAS SUPPLIES
FROM VARIOUS NEW SOURCES* (TCF/YR)

	National Policy of Self-Sufficiency	North American Focus
Lower 48 Conventional	0.5-1.0	0.5-1.0
Synthetic Natural Gas	0.2	0.2
Alaskan	1.3	1.3
Canadian	0.2	0.9
Mexican	0.0	0.9
LNG	0.6	0.6
Coal Gasification	0.3	0.3
Tight Gas	0.2-0.8	0.2-0.8
Other Nonconventional	0.2-0.8	0.2-0.8
	3.5-5.2	5.1-6.8

* Differences between gas supplied in 1981 and 1990 projections. Adapted from Refs. (4) and (15).

5. Non-institutional Constraints

The following are potential non-institutional constraints:

a. Availability of drilling rigs.

b. Construction of an additional main pipeline from the Rocky Mountains to the East.

c. Construction of additional distribution pipelines in the Northeast where most of the oil displacement by NG is required.

d. Storage of NG for seasonal peaking.

e. Technical uncertainties with unconventional gas technologies such as determining characteristics of tight-gas formations.

f. Competition with other capital intensive energy activities for funds.

6. Institutional Constraints

The following are potential institutional constraints:

a. Adequate wellhead price permitted by regulatory agencies to encourage exploration and production of additional conventional and nonconventional gas.

b. Major additional restriction of energy-related activities on Federal lands.

c. Environmental and policy uncertainties such as disposal of water and mine safety in coal-bed gas processing and disposal of brine after extraction of NG from geopressured brines.

d. Regulatory and policy impediments for Canadian and Mexican pipeline imports in an oil emergency.

7. References

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(3) National Petroleum Council. "Executive Summary, Unconventional Gas Sources," December 1980.

(4) "The Gas Energy Supply Outlook, 1980 to 2000," AGA, January 1982.

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(10) "Assessment of Storage and Peaking Strategies," GRI, February 1980 - July 1981, pg. ES-10, Figure ES-7.

(11) Telephone Conversation with Robert Crist of AGA, October 22, 1982.

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